KENTUCKY-AMERICAN WATER COMPANY
CASE NO. 2018-00358
ATTORNEY GENERAL'S FIRST REQUEST FOR INFORMATION

Witness: Ann E. Bulkley

34. Reference the Direct Testimony of Ms. Ann E. Bulkley ("Bulkley Direct"), generally. Provide copies of all articles, regulatory commission orders, rating agency reports, and other supporting documentation cited and relied upon by Ms. Bulkley in her Direct Testimony and exhibits. Include copies of all articles, reports, and other documents cited in the footnotes.

Response:

The requested cited sources are provided in KAW_R_AGDR1_NUM034_Attachment 1 through KAW_R_AGDR1_NUM034_Attachment 49. The attachments are numbered in the order that they appear in the testimony. An index is provided below. Footnote No. 17 on page 17 of Ms. Bulkley's Direct Testimony should be corrected to reference the correct date of the Value Line report which is July 13, 2018.

FN#	Footnote	AGDR1-NUM034 Attachment #
9	The lower bound is based on a recent position established by the Minnesota Department of Commerce in Docket No. E017/GR-15-1033, In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota (August 16, 2016), at 11.	1
10	Bluefield Water Works v. Public Service Comm'n, 262 U.S. 679, 692-93 (1923); Federal Power Comm'n v. Hope Natural Gas, 320 U.S. 591, 603 (1944).	2, 3
11	Kentucky Revised Statute ("KRS") 278.030 part (1).	4
12	Public Service Commission. "PSC Responds to Criticism of Ky. Power." The Mountain Eagle, 2014, www.themountaineagle.com/articles/psc-responds-to-criticism-of-ky-power/.	5
14	Value Line Investment Survey, Water Utility Industry, October 12, 2018 at 1783.	6
15	Value Line Investment Survey, Water Utility Industry, July 13, 2018 at 1783.	7
16	Value Line Investment Survey, Water Utility Industry, October 12, 2018, at 1783.	6

FN#	Footnote	AGDR1-NUM034 Attachment #
17	Value Line Investment Survey, Water Utility Industry, July 13, 2018 at 1783.	7
18	Value Line Investment Survey, Water Utility Industry, October 12, 2018, at 1783.	6
22	S&P Global Market Intelligence, RRA Financial Focus: Utility relative performance and valuation. October 9, 2018, at 1	8
23	Ibid.	8
24	Chakraborty, Tirthankar, "5 Top Bank Stocks to Buy on Surging Bond Yields", Zacks Investment Research, September 20, 2018.	9
25	Merrill Lynch Chief Investment Office, "Capital Market Outlook", May 29, 2018, at 5.	10
26	FERC Docket No. EL11-66-001, Opinion No. 531 (June 19, 2014), footnote 286. While Opinion No. 531 was recently remanded to the FERC by the D.C. Circuit Court on other grounds, that decision did not question the finding by the FERC that capital market conditions were anomalous. Additionally, the methodologies that were relied on by FERC to establish the range have not be challenged. *See also* Federal Energy Regulatory Commission, Docket No. EL 11-66-001, et al., Order Directing Briefs, issued October 16, 2018, at para. 32. This Order develops a proposed methodology to address the issues that were remanded to FERC. The proposed methodology includes an equal weighting of the DCF, CAPM, Expected Earnings and Risk Premium models to better reflect investor behavior and capital market conditions.	11, 12
27	FOMC, Federal Reserve press release, September 26, 2018.	13
28	FOMC, Federal Reserve press release, June 13, 2018.	14
29	Economic projections of Federal Reserve Board members and Federal Reserve Bank presidents under their individual assessments of projected appropriate monetary policy, September 2018.	15
30	Federal Reserve press release, Addendum to the Policy Normalization Principles and Plans, June 14, 2017, implemented at FOMC meeting September 20, 2017.	16
31	Source: Historical data from Bloomberg Professional. Forecast data from Blue Chip Financial Forecasts, Volume. 37, No. 10, October 1, 2018, at 2.	17
32	Blue Chip Financial Forecasts, Vol. 37, Issue No. 10, October 1,	17

FN#	Footnote	AGDR1-NUM034 Attachment #
	2018, at 14.	
33	Ibid.	17
35	Blue Chip Financial Forecasts, Vol. 37, Issue No. 10, October 1, 2018, at 14.	17
38	Source: Blue Chip Financial Forecast, Vol. 37, No. 9, September 1, 2018, at 2.	18
39	FitchRatings, Special Report, What Investors Want to Know, "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector", January 24, 2018.	19
40	Moody's Investors Services, Global Credit Research, Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform, January 19, 2018.	20
41	Moody's Investors Service, "Regulated utilities – US: 2019 outlook shifts to negative due to weaker cash flows, continued high leverage", June 18, 2018, at 3.	21
42	Ibid.	21
43	Ibid.	21
44	Moody's Investors Service Rating Symbols and Definitions, July 2017, at 27.	22
45	Moody's Investors Service Rating Action: Moody's downgrades OGE to Baa1 and Oklahoma Gas & Electric to A2; outlooks remain negative, July 5, 2018, at 2.	23
46	Moody's Investors Service Rating Action: Moody's downgrades Coned to Baa1, CECONY to A3 and O&R to Baa1; outlooks stable October 30, 2018 at 1.	24
47	Moody's Investors Service Rating Action: Moody's changes Xcel Energy's outlook to negative; downgrades Southwestern Public Service ratings to Baa2 with stable outlook, October 19, 2018 at 1.	25
48	Standard and Poor's Global Ratings, "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound," January 24, 2018.	26
49	FitchRatings, Special Report, What Investors Want to Know, "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector", January 24, 2018.	19
50	Standard and Poor's RatingsDirect, "American Water Works Co. Inc. and Subsidiaries 'A' Ratings affirmed; Outlooks	27

FN#	Footnote	AGDR1-NUM034 Attachment #
	Remain Stable," June 11, 2018.	
51	Moody's Investor Services, American Water Works Company, Inc. Update following negative outlook February 16, 2018.	28
53	Standard and Poor's RatingsDirect, "American Water Works Co. Inc. and Subsidiaries 'A' Ratings affirmed; Outlooks Remain Stable," June 11, 2018. Moody's Investor Services, American Water Works Company, Inc. Update following negative outlook February 16, 2018.	27, 28
54	Chediak, Mark, et al. "Utility M&A Is So Hot Not Even Berkshire's Billions Won a Bid." Bloomberg.com, Bloomberg, 3 Jan. 2018, www.bloomberg.com/news/articles/2018-01-03/utility-m-a-is-so-hot-not-even-berkshire-s-billions-won-a-bid.	29
55	French, David, and Liana Baker. "SJW Group Makes $1.1 Billion All-Cash Offer for Connecticut Water." Reuters, Thomson Reuters, 6 Aug. 2018, www.reuters.com/article/us-connecticut-wtr-m-a-sjw-group/sjw-group-makes-11-billion-all-cash-offer-for-connecticut-water-idUSKBN1KR28Y.	30
56	"Aqua America Announces Agreement to Acquire Peoples." Aqua America, 23 Oct. 2018, ir.aquaamerica.com/news-releases/news-release-details/aqua-america-announces-agreement-acquire-peoples.	31
57	Kentucky-American Water Company, Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year, Case No. 2012-00520, Order, October 25, 2013, at 51.	32
58	Kentucky-American Water Company, Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year, Case No. 2010-00036, Order, December 14, 2010, at 70.	33
59	Kentucky-American Water Company, Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year, Case No. 2010-00036, Order, December 14, 2010, at 70.	33
60	Ibid.	33
61	Docket No. 170006-WS, In re. Water and wastewater industry annual reestablishment of authorize range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f),F.S., Order No. PSC-17-0249-PAA-WS, at 2.	34

FN#	Footnote	AGDR1-NUM034 Attachment #
62	Ibid.	34
63	Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed. (New York: McKinsey & Company, Inc., 2000), at 214.	35
64	Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed. (Orlando: Dryden Press, 1994), at 341.	36
65	FERC Docket No. EL11-66-001, Opinion No. 531 (June 19, 2014), fn 286.	11
66	FERC Docket No. EL14-12-002, Opinion No. 551, at para. 121.	37
67	*Id.*, at para. 122.	37
68	Ibid.	37
69	Federal Energy Regulatory Commission, Docket No. EL 11-66-001, et al., Order Directing Briefs, issued October 16, 2018, at para. 40. [Figure 2 was omitted]	12
70	Pennsylvania Public Utility Commission, PPL Electric Utilities, R-2012-2290597, meeting held December 5, 2012, at 80.	38
71	*Id.*, at 81.	38
72	State of Illinois Commerce Commission, Docket No. 16-0093, Illinois-American Water Company Initial Brief, August 31, 2016, at 10.	39
74	State of Illinois Commerce Commission Decision, Docket No. 16-0093, Illinois-American Water Company, 2016 WL 7325212 (2016), at 55.	40
75	File No. GR-2017-0215 and File No. GR-2017-0216, Missouri Public Service Commission, Report and Order, Issue Date February 21, 2018, at 34.	41
76	Docket No. E017/GR-15-1033, In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota (August 16, 2016), at 11.	1
81	Blue Chip Financial Forecasts, Vol. 37, No. 10, October 1, 2018, at 2.	17
82	Blue Chip Financial Forecasts, Vol. 37, No. 6, June 1, 2018, at 14.	42
83	150 FERC ¶ 61,165, Docket Nos. EL11-66-002, Opinion No.	43

FN#	Footnote	AGDR1-NUM034 Attachment #
	531-B (March 3, 2015), at para. 109-111.	
84	*Id.*, at para. 112.	43
85	*Id.*, at para. 113.	43
86	Emera Maine, Request for Approval of a Proposed Rate Increase, Docket No. 2017-00198, Bench Analysis at 71-72 (December 21, 2017); Northern Utilities, Inc. d/b/a UNITIL, Request for Approval of Rate Change Pursuant to Section 307, Docket No. 2017-00065, Bench Analysis, at 15-16 (October 6, 2017).	44, 45
87	Emera Maine, Request for Approval of a Proposed Rate Increase, Docket No. 2017-00198, Bench Analysis, at 71-72 (December 21, 2017).	44
88	Emera Maine, Request for Approval of Proposed Rate Increase, Docket No. 2017-00198, June 28, 2018, at 41.	46
89	S&P, Ratings Direct, "U.S. Regulated Electric Utilities' Annual Capital Spending is Poised to Eclipse $100 Billion," July 2014.	47
90	S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7	48
91	S&P Global Ratings, "Summary: American Water Works Company, Inc.," August 10, 2016, at 3.	49
92	Standard and Poor's RatingsDirect, "American Water Works Co. Inc. and Subsidiaries 'A' Ratings affirmed; Outlooks Remain Stable," June 11, 2018. Moody's Investor Services, American Water Works Company, Inc. Update following negative outlook February 16, 2018.	27, 28

BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, Minnesota 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

IN THE MATTER OF THE APPLICATION OF OTTER TAIL POWER COMPANY FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN THE STATE OF MINNESOTA

Docket No. E017/GR-15-1033
OAH Docket No. 8-2500-33355

CORRECTED - DIRECT TESTIMONY AND ATTACHMENTS OF JOHN P. KUNDERT

ON BEHALF OF

**THE MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES**

AUGUST 16, 2016

CORRECTED - DIRECT TESTIMONY AND ATTACHMENTS OF JOHN P. KUNDERT
IN THE MATTER OF THE APPLICATION OF OTTER TAIL POWER COMPANY FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN THE STATE OF MINNESOTA

MPUC Docket No. E017/GR-15-1033
OAH Docket No. 8-2500-33355

TABLE OF CONTENTS

I. INTRODUCTION, QUALIFICATIONS AND PURPOSE

Q. Would you state your name, occupation, and business address?

A. My name is John P. Kundert. I am employed as a Financial Analyst by the Division of Energy Resources of the Minnesota Department of Commerce (Department or DOC), Suite 500, 85 7th Place East, St. Paul, Minnesota, 55101.

Q. What is your educational and professional background?

A. I have twenty-four years of experience working in the economic regulation of fixed utilities. I have prepared and defended testimony on issues such as rate of return, rate design, cost of service and environmental costs. I have also authored and analyzed miscellaneous filings related to rate design, financial tools, mergers and other issues related to utility regulation. A complete summary of my educational and professional background is presented in DOC Ex. ___ at JPK-1 (Kundert Direct).

Q. What is your responsibility in this proceeding?

A. My responsibility is to determine a fair rate of return on common equity capital and a fair overall rate of return for Otter Tail Power Company (OTP or the Company).

Q. Please summarize your recommendations on OTP's proposed rate of return on equity and overall rate of return.

A. Based on my analysis, I recommend a return on common equity of 8.87 percent and an overall rate of return of 7.27 percent for OTP. My proposed return on common equity is 153 basis points lower than OTP's proposed level of 10.40 percent[1]. My proposed overall rate of return is 80 basis points lower than OTP's proposed level of 8.07 percent.

II. OVERVIEW OF COST OF COMMON EQUITY

Q. Please explain the concept of a fair rate of return.

A. A fair rate of return is, by definition, the rate that, when multiplied by the rate base, will give the utility a reasonable return on its investment (Minn. Stat. §216B.16, subd. 6). The sum of a utility's fair return, operating expenses, depreciation expenses and taxes equals the utility's total revenue requirement.

Q. Why is the Minnesota Public Utilities Commission (Commission) responsible for determining OTP's fair rate of return?

A. OTP, a rate-regulated public utility, is a monopoly provider of electric utility service in its assigned service territory. A monopoly provider has strong economic incentives to provide a lower level of service and price those services at a rate higher than would be optimal from a societal perspective. In light of these economic incentives or tendencies, the Minnesota Legislature has tasked the Commission with determining a monopoly service provider's rate of return. The Legislature has also directed the Commission to develop a "fair and reasonable" return. *See* Minn. Stat. §§ 216B.01, 216B.03, 216B.16, subd. 6 (2014).

[1] Investopedia defines a basis point as "a common unit of measure for interest rates and other percentages in finance. One basis point is equal to 1/1000th of 1% or 0.01% (0.0001), and is used to denote the percentage change in a financial instrument. The relationship between percentage changes and basis points can be summarized as follows: 1% change = 100 basis points and 0.01% - 1 basis point. www.investopedia.com/terms/b/basispoint.asp.

Q. Is the Commission's task in this regard somewhat unusual from a societal perspective?

A. Yes, in a competitive environment, prices (rates) and operating incomes (returns) are determined by the free interaction of market forces, primarily supply and demand. These market forces ensure, under certain conditions, that an optimum level and mix of various goods and services are produced.

But in the regulated utility industry, the role normally assumed by competition is assumed by regulatory agencies, which must ensure that public utilities provide an appropriate supply of satisfactory services at reasonable rates. To provide these services the utility must be able to compete for necessary funds in the capital markets. To attract these funds, the utility must earn enough to offer competitive returns to investors. Thus, a fair return is one that enables the utility to attract sufficient capital, at reasonable terms.

Q. What guidelines did you use to determine the fair rate of return on common equity capital for OTP?

A. Consistent with Department policy and precedent, I used the following economic guidelines, as set forth in the Bluefield and Hope cases (*Bluefield Water Works & Improvement Co. v. Pub. Service Comm'n of W. Virginia,* 262 U.S. 679 (1923) and *Fed. Power Comm'n. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Bluefield* and *Hope*):

1. The rate of return should be sufficient to enable the regulated company to maintain its credit rating and financial integrity.

2. The rate of return should be sufficient to enable the utility to attract capital.

3. The rate of return should be commensurate with returns being earned on other investments having equivalent risks.

I am also familiar with the Department's testimony regarding the cost of capital, especially in Great Plains Natural Gas Company and Northern States Power Company's most recent general rate cases, Docket Nos. G004/GR-15-879 and E002/GR-15-826.

Q. Please explain the methods you used to determine the cost of common equity capital for OTP.

A. The cost of equity capital to OTP is the rate of return necessary to induce investors to invest in its regulated operations. To estimate this cost I used a market-oriented approach and relied on the concept of "opportunity costs."

Q. Please explain.

A. Investors are faced with many investment opportunities in the financial markets. To attract investors, OTP must pay an equity return similar to the equity return that investors expect to earn on investments of comparable risk. This rate of return is the cost of equity capital to OTP. When investors buy the common stock of a utility, they acquire the right to share any dividends that the company may declare in the future. The prospect of these dividends serves as an inducement to investors.

Q. How does a potential investor in common equity capital know what dividends a company will pay in the future?

A. Investors form certain expectations about future dividends, based on the company's past and current performance, the company's prospects for future growth, and investors' perceptions of the current and future economic environment. However, investors do not know with certainty what dividends a company will pay in the future and recognize that there is a risk that future dividends will be lower than expected. They also understand that dividends may be higher than expected.

Q. Given the need to set a reasonable rate of return on equity in this case in light of the factors you have discussed, what method do you recommend for the Commission to use in this proceeding?

A. I recommend that the Commission use the Discounted Cash Flow (DCF) model to determine OTP's return on equity in this proceeding. The DCF model postulates that the current price of a stock is equal to the present value of all expected future dividends, discounted by the appropriate rate of return. The DCF model is a fair, market-oriented method that uses current, relevant information to determine a rate of return on equity that would allow OTP to compete sufficiently and fairly in the capital markets.

Q. How does the DCF model work?

A. The appropriate rate of return reflects the risk associated with the expected flow of future dividends. The DCF model can be expressed mathematically as:

$$P = D_1/(1+k) + D_2/(1+k)^2 + D_3/(1+k)^3 + \ldots + D_\infty/(1+k)^\infty \text{ [Eq. 1]}$$

where P is the current price of the stock; D_1 is the expected dividend at the end of period one, D_2 is the expected dividend at the end of period two, etc.; and k, the discount rate, is the rate of return that the average investor requires as compensation for the risks associated with owning the stock, known as the cost of equity.

In the special case that dividends are expected to grow at a constant rate over time, known as the "constant growth rate DCF", Equation 1 above can be rewritten as:

$$P = D_1/(1+k) + D_1(1+g)/(1+k)^2 + D_1(1+g)^2/(1+k)^3 + \ldots + D_1(1+g)^{\infty-1}/(1+k)^{\infty} \quad \text{[Eq. 2]}$$

Where D_1 is the expected dividend at the end of period one and g is the constant growth rate at which dividends are expected to grow. Equation 2 is an infinite geometric series which, as long as g is less than the cost of equity k, can be solved for, algebraically rearranged, and expressed as:

$$k = (D_1/P) + g \qquad \text{[Eq. 3]}$$

Equation 3 essentially states that the cost of equity is equal to the sum of a stock's expected dividend yield and its expected growth rate.

While the cost of equity cannot be observed directly, with estimates of a stock's expected dividend yield (in one year) and its dividend growth rate, the cost of equity can be estimated using Equation 3. I perform this analysis later in my testimony.

Q. In addition to the constant growth rate DCF, do you propose to use any other versions of the DCF model to estimate OTP's cost of equity?

A. Yes. Later in my testimony, I also estimate OTP's cost of equity using the "two-growth-rates DCF," which assumes that dividends grow at one rate for a short time, and then grow at a second, sustainable rate in perpetuity.

Q. Have you prepared Attachments for use in determining the fair rate of return on common equity for OTP?

A. Yes. I prepared eleven Attachments, DOC Ex. ___ at JPK-2 (Kundert Direct) through DOC Ex. ___ at JPK-12 (Kundert Direct) to illustrate how I determined the fair rate of return on equity and the overall cost of capital that I propose for OTP.

Q. Does your analysis depend only on OTP-specific data?

A. No. OTP is a subsidiary company of Otter Tail Corporation (OTC). As such, OTP is not publicly traded on any of the stock exchanges, and therefore cannot be analyzed directly with a DCF analysis.[2]

Q. How then do you propose to use a DCF analysis to estimate OTP's required rate of return on common equity?

A. When a company's (or division's) stock is not publicly traded and cannot be analyzed directly with a DCF analysis, an alternative is to perform a DCF analysis on a group (or groups) of proxy companies whose investment risk is comparable to the investment risk posed by OTP. To estimate the cost of equity for the Company, I apply DCF

[2] OTP is a bit unusual from the DOC's perspective in that the electric utility maintains its own credit rating as opposed to simply being included in the credit rating of the parent company. I used the OTP-specific credit rating information in my analysis.

analyses to two groups of companies with investment risks similar to OTP. Additionally, I use the Capital Asset Pricing Model (CAPM) to support my DCF analysis.

III. SELECTION OF THE DOC PROXY GROUP

Q. You previously indicated that you performed DCF analyses on a group of companies with investment risks similar to that of OTP. What, ultimately, is your goal in selecting companies for the proxy group?

A. It is a well-accepted financial principal that companies with similar investment risks are expected to have similar required rates of return. Thus, my goal in selecting companies for the proxy group is to select companies that pose risks to equity investors similar to the risks OTP poses.

Q. Please discuss the measures of investment risk you used in assessing the expected risk of OTP.

A. In general, investment risks are divided into two groups: financial risks and business risks. First, financial risks are the risks associated with debt financing, and are twofold. Debt financing increases the volatility of future earnings and also creates the possibility of bankruptcy as a company with debt must continue to repay its debt even if earnings are low.

Second, business risks are related to the uncertainty of future earnings due to characteristics of the business, such as changes in future demand, future costs, market structures, etc.

Q. Please discuss the various risk screens you applied to choose the group of companies that have investment risk comparable to OTP.

A. I began the screening process for my initial proxy group by running a search in the Research Insight database for companies that have a Standard Industrial Classification (SIC) code of 4911: Electric Services, and that are traded on one of the major stock exchanges. I refer to this group of proxy companies as the 4911 Proxy Group

Q. Please explain the first criterion, regarding SIC codes.

A. The SIC code system is a classification system used by various government agencies to classify companies by type of business. SIC 4911: Electric Services is assigned to companies engaged in the generation, transmission, and/or distribution of electric energy for sale. Limiting the comparison to companies with an SIC code of 4911 ensures that the companies in the proxy group operate in the same line of business as OTP, and thus may have business risks similar to the business risks of the Company.

Q. Please explain the second criterion listed above, regarding stock exchanges.

A. One of the data inputs required to perform a DCF analysis is the price of a share of stock in the company. When selecting a comparison group of companies, it is therefore necessary to select companies with publicly traded stock, which ensures that the companies' share prices will be publicly available and set by market forces.

Q. How many companies did your initial search identify, applying the criteria mentioned above?

A. My initial search produced a list of 44 companies, including OTP's parent Otter Tail Corporation (OTC). I removed OTC from the list to avoid issues of circularity that would result from including Otter Tail Corporation in my analysis. The remaining 43 companies are shown in DOC Ex. ___ JPK-2 Schedule 1 (Kundert Direct).

Q. Did you apply additional screens?

A. Yes. From this list, I eliminated companies that have a Standard & Poor's (S&P) credit rating outside of the range of BBB- to BBB+ (or are not rated by S&P). As noted in Table 4 of the Direct Testimony of OTP Witness Kevin Moug, OTP has an S&P corporate rating of BBB. Companies that have credit ratings similar to OTP may have comparable risk profiles and are therefore suitable for inclusion in proxy groups used to estimate OTP's risk, while companies with credit ratings that are significantly higher or lower than OTP's may have different risk profiles that render them unsuitable for inclusion in the proxy groups. The range of credit ratings I used to screen utilities, from BBB- to BBB+, is one step above and below OTP's credit rating of BBB.

I also eliminated companies that:

1. Are incorporated outside of the U.S.
2. Are known to be involved in merger or acquisition activity;
3. Are covered by fewer than two equity analysts;
4. Do not pay consistent dividends;

5. Are not covered by the investor service Value Line and at least one additional investor service, either Zacks Investment Research (Zacks) or Thomson First Call Consensus (Thomson); and
6. Receive less than 60 percent of their operating income from regulated electric operations.

DOC Ex. ___ JPK-2, Schedule 1 (Kundert Direct) summarizes the results of the screening process to this point. I refer to this group as the initial 4911 Proxy Group.

Q. Did you apply any further screens?

A. Yes, I applied one additional screen. Any method of estimating the required rate of return, including DCF analysis, must survive the test of reasonableness based on well-established financial principles. In a DCF analysis, the results should not be mechanically accepted if they violate well-accepted financial principles. For example, it is important for companies in the DOC proxy group to be financially viable because it is in the public interest, including the interest of ratepayers, for the utility to have a reasonable opportunity to recover its costs; setting the return on equity (ROE) too low would not give the utility a reasonable opportunity to finance the necessary capital improvements to its system.

Thus, after selecting my initial 4911 Proxy Group, I performed a constant growth DCF analysis for each company, as shown in DOC Ex. ___ JPK-2, Schedule 3 (Kundert Direct). Four companies – Edison International (EIX), Entergy Corp. (ETR), FirstEnergy (FE) and IDACORP, Inc. (IDA) have ROEs of less than seven percent. Such low ROEs do not survive the test of financial reasonableness in that they may not reflect financially viable companies or at least do not represent reasonable ROEs that are likely to induce investors to purchase stock.

Q. On what basis do you conclude that ROEs less than seven percent are not reasonable?

A. Financial reasonableness means that expected ROEs should at least be sufficient to compensate investors for the risk of owning stock in companies rather than a lower-risk asset. The difference between the required return for stock and the required return for a lower risk asset (like a corporate bond) is known as a risk premium. According to the Capital Asset Pricing Model (CAPM), which I discuss in greater detail later in this Testimony, the risk premium for a particular company is defined as follows:

$$\text{Risk Premium} = \text{beta} \times (r_m - r_f),$$

Where beta is a measure of the systematic risk of the stock, r_m is the required rate of return on the market portfolio, and r_f is the rate of return on a riskless asset. Using the S&P 500 index as a proxy for the market portfolio, the current yield on 20-year Treasury bonds as a proxy for the riskless asset, and the average betas of the companies in my 4911 proxy group, I estimate that the risk premium for the 4911 group is 5.94. See DOC Ex. ___ JPK-2, Schedule 4. In other words, the investor's required return for investments in these companies is 5.94 percent higher than the required return on an investment in 20-year Treasury bonds.

Given the current yield on 20-year Treasury bonds, 1.95 percent, a stock with a cost of equity of 7 percent has risk premium of 5.05 percent (equal to 7 percent less 1.95 percent), or 89 basis points less than the average risk premium of 5.94

percent identified in DOC Ex. ___ JPK-2, Schedule-4 (Kundert Direct). This result indicates that a seven percent ROE likely would not be sufficient to compensate investors for the additional risk associated with investing in an electric utility rather than 20-year Treasury bonds.

Q. Has the Department used a different threshold in past rate cases?

A. Yes and no. In Docket No. E002/GR-13-868 (the 2013 Northern States Power Minnesota Rate Case), the Department eliminated companies with a DCF result below eight percent. A threshold of eight percent was supported at the time by the Department's CAPM results. In Docket No. E002/GR-15-826, Northern States Power Minnesota's most recent rate case, the Department eliminated companies with a DCF result below seven percent. Market conditions at that time supported the new lower threshold. As demonstrated above, current market conditions continue to support the seven percent threshold.

Q. Please list the final members of the 4911 proxy group.

A. Table 1 contains this information.

Table 1
DOC 4911 Proxy Group

Company	Ticker
AMERICAN ELECTRIC POWER	AEP
EL PASO ELECTRIC CO	EE
PNM RESOURCES INC.	PNM
PORTLAND GENERAL ELECTRIC CO	POR

Q. Do you have any concerns regarding the 4911 Proxy Group?

A. Yes. As an analyst I am concerned that a proxy group that consists of only four companies is not robust for a proceeding of this nature.

Q. Please continue.

A. It is increasingly difficult to choose a sufficiently large group of risk-comparable electric companies. The ongoing consolidation in the electric industry makes it difficult to select a sufficiently large group of electric utilities. As a result, the size of a comparable group that only draws companies from the 4911 SIC Code becomes smaller over time.

Q. Why is the smaller size of the 4911 Proxy Group a problem?

A. The required rate of return on equity for any electric utility is calculated by using various estimation methods such as the Discounted Cash Flow or Capital Asset Pricing Model. These methods require using forecasted or estimated data such as dividend growth rates, betas, risk premium, etc. Therefore, the required rates of return obtained by using the various methods are estimated, not certain, required rates of return. When using a small number of companies in the comparison group, the estimated rates of return may be highly influenced by the estimated required return of any one or two companies in the comparison group. Thus an analyst may need to examine more closely the estimated required rate of return for any individual company in the comparison group, or increase the size of the proxy group if it is possible to identify additional companies with similar risk profiles.

Q. How did you address your concerns regarding the 4911 Proxy Group?

A. I elected to develop a second proxy group using the 4931 SIC code (Electric and Other Services Combined).

Q. How did you begin the screening process for your second proxy group?

A. I began the screening process for my second proxy group by running a second search in the Research Insight database for companies that have an SIC code of 4931: Electric and Other Services Combined, and that are traded on one of the stock exchanges. I refer to this group of proxy companies as the 4931 Proxy Group.

Q. Please describe SIC Code 4931.

A. SIC code 4931: Electric and Other Services Combined is assigned to companies primarily engaged in providing electric services in combination with other services: with electric services as the major part though less than 95 percent of the total. While these companies provide services other than electric services, because they are primarily engaged in the provision of electric services, they may have business risks similar to the business risks of the Company.

Q. What selection criteria did you use for companies identified with a 4931 SIC Code?

A. I used the same selection criteria as I used for the 4911 SIC code discussed earlier in my testimony. I eliminated companies that

1. Have a S&P bond rating outside the BBB- to BBB+;
2. Are incorporated outside of the U.S.;
3. Are known to be involved in merger or acquisition activity;

4. Are covered by fewer than two equity analysts;
5. Do not pay consistent dividends;
6. Are not covered by the investor service Value Line and at least one additional investor service, either Zacks or Thomson;
7. Receive less than 60 percent of their operating income from regulated electric operations; and
8. Have an ROE below 7 percent using a constant growth DCF analysis.[3]

Q. How many companies did your second search, applying the criteria mentioned above, identify?

A. My second search produced a list of eight companies, shown in DOC Ex. ___ JPK-2, Schedule 2 (Kundert Direct). I defined this group as the 4931 Proxy Group. Table 2 lists the eight companies.

Table 2
DOC 4931 Proxy Group

Company	Ticker
ALLETE INC	ALE
AMEREN CORP	AEE
AVISTA CORP	AVA
CMS ENERGY CORP	CMS
DTE ENERGY CO	DTE
NORTHWESTERN CORP	NWE
PG&E CORP	PCG
SCANA CORP	SCG

[3] As with the 4911 proxy group, I calculated the risk premium for the initial 4931 comparable group to determine the reasonable expected return above the 20-year Treasury bond yield needed to attract capital. The risk premium for the 4931 proxy group is 5.87 percent. Adding 5.87 percent to the 1.95 percent U.S. Treasury bond yield is 7.82 percent; therefore, the 7 percent ROE threshold is a reasonable screen for both proxy groups. DOC Ex. __ at JPK-2, Schedule 6.

Q. How did you use the two proxy groups you developed in your analysis?

A. I combined the 4911 and 4931 Proxy Groups into one proxy group, consisting of 12 companies. I defined this group as the DOC Proxy Group.

Q. Please list the final members of the DOC Proxy Group.

A. Table 3 contains this information.

Table 3
Final DOC Proxy Group

Line No.	Company	Ticker
1.	ALLETE INC	ALE
2.	AMERICAN ELECTRIC POWER	AEP
3.	AMEREN CORP	AEE
4.	AVISTA CORP	AVA
5.	CMS ENERGY CORP	CMS
6.	DTE ENERGY CO	DTE
7.	EL PASO ELECTRIC CO	EE
8.	NORTHWESTERN CORP	NWE
9.	PG&E CORP	PCG
10.	PNM RESOURCES INC.	PNM
11.	PORTLAND GENERAL ELECTRIC CO	POR
12.	SCANA CORP	SCG

Q. In your opinion, does the DOC Proxy Group present a group of companies that are comparable in risk to OTP?

A. Yes. I used eight screening criteria, all of which are valid, to identify companies that are comparable in risk to OTP as a regulated electric utility.

IV. COST OF EQUITY CALCULATION

Q. Please describe the methods you used to estimate OTP's cost of equity.

A. I used the constant growth rate DCF model and the two-growth-rates DCF model to estimate OTP's cost of equity. I also use the CAPM to confirm that my DCF results are reasonable.

A. CONSTANT GROWTH RATE DCF ANALYSIS

Q. Please describe how an analyst can estimate a company's cost of equity using the constant growth rate DCF model.

A. A company's cost of equity (k) can be expressed as the sum of a stock's expected dividend yield and its expected growth rate under the assumptions of the constant growth rate DCF. As described earlier, Equation 3 delineates this relationship:

$$k = (D_1/P) + g \qquad \text{[Eq. 3]}$$

Q. Please explain how Equation 3 can be used to estimate the cost of equity for the members of the DOC Comparable Group.

A. Estimates of each member's expected growth rate (g), the second term in Equation 3, can be sourced from investment research services. Each company's dividend yield, the first term in Equation 3, can be estimated using its current stock price (P), which is directly observable, it's most recent dividend (D_0), which is also directly observable; and the company's expected growth rate.

Q. Please describe the expected growth rates you used in your DCF analyses.

A. I used projected earnings growth rates provided by Zacks, Value Line, and Thomson.

For both of my DCF analyses I estimate the cost of equity for each member of the DOC Proxy Group using the average of the three growth rates, the highest of the three growth rates, and the lowest of the three growth rates.

Q. Why do you use earnings growth rates rather than dividend growth rates?

A. Over the long run, growth in dividend per share (as well as growth in book value per share) is derived from the growth in earnings per share (EPS). While the short-run growth in dividends may be influenced by management's policy decisions, the long-run sustainable growth in dividends is solely driven from the growth in earnings. In addition, the use of projected earnings growth rates is well supported by various financial studies and publications.[4] For example, a paper published in "The Journal of Portfolio Management," Spring 1998, shows that projected EPS growth rates are the best predictors of stock prices (Investor Growth Expectations: Analysts vs. History: James H. Vandor Weide and Willard T. Carleton).

Q. Please discuss the dividend yields you used in your DCF analyses.

A. The dividend yield in Equation 3 is equal to the expected dividend at the beginning of the next period (year) divided by the current price (*i.e.*, D_1/P_0). Thus, an estimate of

---

[4] In the Risk Premium Approach to Measuring a Utility's Cost of Equity, published in Financial Management, Spring 1985, Brigham, Shome, and Vinson noted that: "evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts solely based on time series data, and (ii) investors do rely on analysts' forecasts. Similarly, in a review of literature regarding the extent to which analyst forecasts are reflected in stock prices (Using Analyst's Growth Forecasts to Estimate Shareholder Required Rates of Return, Financial Management, Spring 1986), Harris noted: "Vander Weide and Carleton recently compared consensus [financial analyst forecasts] of earnings growth to 41 different historical growth measures. They conclude that 'there is overwhelming evidence that the consensus analysts forecast of future growth is superior to historically-oriented growth measures in predicting the firm's stock price . . . consistent with the hypothesis that investors use analyst's forecasts, rather than historically-oriented growth calculations, in making stock buy and sell decisions." See also, Harris and Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," Financial Management 21 (Summer 1992).

the dividend yield requires an estimate of the expected dividend at the beginning of the next year, and an estimate of the current stock price.

The DCF model assumes that dividends are paid once a period (year). The dividend yield in Equation 3 above is calculated as the expected annual dividend in the next period (D_1) divided by the current stock price (P_0), and thus requires an estimate of each company's annual dividend to be paid one year from now. However, companies generally pay quarterly dividends. To estimate the current level of each company's dividend, I annualized the most recent quarterly dividend by multiplying it by four.

Additionally, companies increase their dividends in different quarters during the year. The companies in the DOC Proxy Group may increase their dividends during any of the next four quarters. Some companies will increase their dividends in the first or second quarters, and others will increase it during the third or fourth quarters. Thus, it is reasonable to estimate each company's expected annual dividend in the next period by averaging these expectations and assuming a half years' worth of growth. I therefore calculate the expected dividend in the next period as:

$$D_1 = D_0(1+0.5g)$$

Q. Describe how you calculate the share price in the current period.

A. Because share prices can be volatile in the short run, it is desirable to use an average share price over a period of time long enough to avoid short-term aberrations in the capital market. However, the share price at any point in time in the past will necessarily fail to reflect any news or information arising after that point in time that may materially affect the share price. Thus, the period of time should not be too long in order to ensure that the measure of the price used to calculate the expected dividend yield appropriately reflects all relevant publically available information. In order to balance these competing goals, for purposes of calculating each company's expected dividend yield, I calculate share price as the average of the closing price over the 30 trading days ending July 15, 2016.

Q. Could you summarize the results of your constant growth rate DCF analysis?

A. The results of my constant growth rate DCF analysis are summarized in **CORRECTED -** Table 4.

CORRECTED - Table 4 Summary of Constant Growth Rate DCF ROE Results Before Adjustment for Flotation Costs			
Description	Mean Low	Mean Average	Mean High
DOC Final Proxy Group	8.00%	8.89%	9.87%
Sources:			
REVISED DOC Ex. ___ JPK-3, CORRECTED - Schedule 1			

Q. Do you propose to use the mean constant growth rate DCF result for the DOC Comparable Group of 8.88 percent to recommend a rate of return on equity for OTP?

A. No. The growth estimates I use from Zacks, Value Line and Thomson are all five-year growth projections, and some of them may not be reasonable to use as proxies for the DCF's long-term sustainable growth rates.

Q. Please explain.

A. As noted above, using analysts' forecasted earnings growth rates is the best approach to estimate the cost of equity using the DCF method. There may be circumstances under which the five-year forecasted growth rates are clearly not sustainable in the long run, however. Given that the DCF analysis assumes that growth rates are constant in perpetuity, the five-year forecasted growth rates, when not sustainable in the long-run, are not appropriate for use in a constant growth DCF model.

Q. Please explain the concept of sustainable growth rates.

A. It is possible that investors may have different short-term and long-term expectations in regards to a company's financial performance and earnings growth rate. As a result, it may be appropriate to use more than one growth rate in a DCF analysis. The two-growth-rates DCF, for example, uses one growth rate for the first five years, and then a second, sustainable growth rate for year six and beyond.

B. TWO-GROWTH-RATES DCF ANALYSIS

Q. Please discuss your two-growth-rates DCF analysis.

A. The two-growth-rates DCF model accounts for situations where the short-term projected growth rates may not be expected in the long-run. The short-term earnings growth rate may be unusually lower or unusually high, relative to the company's historical averages, industry averages, or relative to the economy as a whole. Unusually low or high growth rates may result in unreasonably low or high estimates of the cost of equity. The two-growth-rates DCF model accommodates two different growth rates: one for the short-term and one for the long-term, representing a sustainable growth rate.

Q. Please state the two-growth-rates DCF formula.

A. The two-growth-rates DCF formula as shown below uses the short-term growth rate for the first five years, and the long-term growth rate in years six and beyond. The two-growth-rates DCF formula is:

$$P = (D_1/(1+k)) + (D_1(1+g_1)/(1+k)^2) + (D_1(1+g_1)^2/(1+k)^3) + (D_1(1+g_1)^3/(1+k)^4) + (D_1(1+g_1)^4/(1+k)^5) + (D_1(1+g_1)^4(1+g_2)/(k-g_2)) \times 1/(1+k)^5 \text{ [Eq. 4]}$$

The first five terms of Equation 4 are the dividends in years one through five, growing at the first growth rate, g_1, discounted back to the present using the required rate of return or cost of equity, k. The sixth term in Equation 4 is the stock price in year five, estimated as the dividend in year six divided by k minus the second growth rate, discounted back to the current year.

Q. What did you use for your short-term growth rates in your two-growth-rates DCF analysis?

A. The growth rates I used in the constant growth rate DCF analysis, from Zacks, Value Line, and Thomson, are five-year projected earnings growth rates. Because the short-term period in my two-growth-rates DCF analysis represents the first five years of the analysis, I used those projections as the short-term growth rates in my two-growth-rates DCF.

Q. What did you use for your long-term growth rates in the two-growth-rates DCF analysis?

A. For the long-term growth rates, I used the same growth rates as I used in the constant growth rate DCF analysis for the members of the DOC Proxy Group for which

I determined that those growth rates are sustainable. For those I determined are unsustainable in the long-run, I used a substitute growth rate.

Q. How did you determine whether the short-term growth rates are reasonable for use as long-term sustainable growth rates?

A. I calculated the average growth rate for the DOC Proxy Group, as well as the standard deviation of the growth estimates. I added and subtracted one standard deviation to the average growth rate to develop the upper and lower bounds for long-term sustainable growth rates.

Q. What long-term growth rate did you use for companies whose short-term growth rates were either above or below the short-term average growth rate plus or minus one standard deviation?

A. If a company's short-term growth rate was more than one standard deviation below (above) the DOC's Proxy Group's average short-term growth rate, I substituted the DOC Proxy Group's average minus (plus) one standard deviation.

Q. Please summarize the results of your two-growth-rates DCF analysis.

A. My two-growth-rates DCF results are summarized in **CORRECTED** - Table 5.

CORRECTED - Table 5			
Summary of Two-Growth Rate DCF ROE Results			
Before Adjustment for Flotation Costs			
Description	Mean	Mean	Mean
	Low	Average	High
DOC Final Proxy Group	7.98%	8.74%	9.61%
Sources:			
REVISED DOC Ex. ___ JPK-3, CORRECTED and UPDATED - Schedules 2-4			

Q. Do you propose to use these DCF results to determine the appropriate return on equity for OTP?

A. No. My DCF results shown above must be adjusted to account for the impact of flotation costs.

C. FLOTATION COSTS

Q. What are flotation costs?

A. Flotation costs are defined as the costs of issuing new shares of common stock. In general, the DCF results must be adjusted to allow for the cost of issuing new shares of common stock without causing dilution. Due to issuance costs, the price paid by an investor for a new share is higher than the price received by the company issuing the new share. These issuance costs are recognized by adjusting the required rate of return. This adjustment is appropriate even if no new issuances are planned in the near future because failure to allow such an adjustment may deny OTP the opportunity to earn its required rate of return in the future. Such a denial is contradictory to the purpose of rate of return regulation.

Q. Can you provide an example that explains why the price paid for a new share of common stock is higher than the price received by the company issuing the new share?

A. Yes, through an example. Assume that a company needs to raise $96 in equity capital. The company's current stock price is $10 per share. As a result, the company reasons that, if it issues ten shares of stock at the current price of $10 per share, it will receive an amount of new equity capital of around $96 after accounting for transactions costs. In order to sell, or "float" the ten new shares of stock, the company has to pay an investment banker to complete the paper work and place the stock. For this example, let's assume the investment banker's fee is equal to 4 percent.

The investment banker places the 10 new shares of stock at a price of $10.00 per share. The investment banker receives $100 from the investors that purchased the 10 new shares of stock. The investment banker subtracts its $4.00 fee from the $100 it received and sends the remaining $96 in cash to the company.

In this example, the investors that purchased the stock paid $10 per share for 10 shares of stock, or $100. But the company that issued the stock only received $96.00 or $9.60 per share ($96.00/10 shares).

Q. In your hypothetical, why is the fact that the company sold $100 worth of equity, but only received $96 in cash from the sale a cost of equity related to the issue of setting an ROE in a general rate case?

A. When a company, or any of the other stakeholders, estimates the company's cost of equity using a proxy group, those analysts use the current share price that an investor would pay for a share in one of the various companies in the proxy group ($10.00/share in the example), not the net amount per share that the particular company received when it issued the equity ($9.60/share in the example). Thus, the cost of equity for one of the companies included in the proxy group is calculated using the amount an investor would pay to acquire a share, not the amount per share net of the transaction fee the company received.

Q. Please continue.

A. In the example above, the issue of concern is that, without inclusion of flotation costs, the cost of equity derived using the market value per share for a company included in the proxy group would underestimate the company's cost of equity by using the higher market price of a share of common equity ($10.00 from the example) instead of the amount per share the company actually received ($9.60 from the example).

To address this underestimation of the cost of equity, analysts developed a "flotation cost adjustment".[5] A flotation cost adjustment uses the issuing costs for common equity to develop an estimate of those "transactions costs." The estimate is based on information specific to the petitioning company (OTP in this case using costs related to OTC issuing equity), or for the companies included in the proxy group (if the petitioning company doesn't issue stock). As a rule of thumb, the flotation cost adjustment is often around 3 to 4 percent of the total flotation costs divided by the gross equity issuance before costs.

---

[5] Merriam-Webster defines flotation as "an act or instance of financing (as an issue of stock)". www.merriam-webster.com/dictonary/flotation.

Q. What are OTP's proposed issuance costs in this proceeding?

A. OTP estimates OTC's issuance costs since 2008 to be 3.944 percent.

Q. How do you propose to adjust the cost of equity to recognize OTP's estimated flotation costs?

A. The dividend yields of the companies in the company's proxy group must be adjusted by dividing them by 1-F, where F is the percentage of flotation costs.

Q. Can you provide another example of how this calculation works?

A. Yes. Assume the proxy group consists of two companies. Company A has a dividend yield of 3 percent and an expected annual growth rate of 4 percent annual growth rate over the next several years. Company B has a dividend yield of 3.5 percent and an expected annual growth rate of 5 percent over the next several years.

The Constant DCF result for Company A without considering the effect of flotation costs is equal to the current dividend yield (3 percent) plus the expected annual growth rate (4 percent) or 7 percent. The equation to determine the dividend yield after accounting for flotation costs is 0.03 x (1 - .03944) = 0.02882 or 2.88 percent. Thus, Company A's estimated cost of equity after accounting for flotation costs is 2.88 plus 4.00 percent, or 6.88 percent.

Performing the same calculation for Company B results in an estimated cost of equity of 8.5 percent (3.5 percent + 5.0 percent). Company B's cost of equity after accounting for flotation costs is 8.36 percent (3.5 x (1 - 0.03944)) + 5.0).

The next step is to subtract the DCF results accounting for flotation costs from the original DCF results for both Company A and B. The result for Company A is 7.00

percent – 6.88 percent = 0.12 percent (or 12 basis points). The result for Company B is 8.50 percent – 8.36 percent = 0.14 percent (or 14 basis points). The final step is to average the results for the two companies, which results in a flotation cost adjustment of 0.13 percent (or 13 basis points).[6]

Q. How does OTP's proposed flotation cost adjustment compare to the example you just developed?

A. As I noted earlier, based on OTP Ex. ___ at RBH-1, Schedule 2, Page 1 of 1 (Hevert Direct), the value of flotation costs, F, is 3.944 percent. Mr. Hevert (the Company's witness on return on equity) then calculates OTP's flotation costs using his comparable group, which contains nine companies.

I reviewed the Company's calculations and conclude that Mr. Hevert's approach for calculating flotation costs is adequate. I agree with Mr. Hevert that the appropriate weighted average flotation cost for OTP is 3.944 percent.

Q. Do you agree with Mr. Hevert's proposed flotation cost adjustment of 16 basis points?

A. No, I adopted Mr. Hevert's approach, but replaced the OTP Proxy Group with the DOC Proxy Group and updated the other inputs in the Constant Growth DCF calculation. The resulting estimate of the flotation cost adjustment using this approach and updated information is 13 basis points.[7]

---

[6] The averaging calculation is (0.14 percent + 0.12 percent)/2 = 0.13 percent.
[7] A modified version of Company's Ex. ___ at RBH-1, Schedule 2 (Hevert Direct) as described is included as DOC Ex. ___ at JPK-3, Schedule 7 (Kundert Direct).

Q. Please summarize the results of your Two-Growth-Rates DCF analyses once you include the flotation cost adjustment.

A. My two-growth-rates DCF ROE estimates for the DOC Proxy Group, including flotation costs, ranges from a low of 8.10 percent to a high of 9.72 percent, with an average of 8.86 percent.

Q. Please summarize the results of your Constant Growth Rate and Two-Growth-Rates DCF analyses.

A. CORRECTED Table 6 contains that information.

CORRECTED - Table 6 Summary of DCF ROE Results Including Flotation Costs Adjustment			
Model	Low	Mean	High
Constant Growth DCF	8.13%	9.01%	9.99%
Two-Growth DCF	8.10%	8.87%	9.73%
Sources:			
REVISED DOC Ex. ___ JPK-3, CORRECTED and UPDATED Schedules 1-4 (Kundert Direct)			

D. THE CAPITAL ASSET PRICING MODEL

Q. Have you used any method other than the DCF model to estimate the required rate of return on equity for OTP?

A. As noted previously, I used the Capital Asset Pricing Model (CAPM) as a check on the reasonableness of my DCF analyses.

Q. Please explain the CAPM.

A. The CAPM's basic premise is that any company-specific risk can be diversified away by investors. Therefore, the only risk that matters is the systematic risk of the stock, which is measured by beta. In its simplest form, the CAPM assumes the following:

$k = r + \text{beta}\ (k_m - r)$, where:

k is the required rate of return for the stock in question;

r is the rate of return on a riskless asset; and

k_m is the required rate of return on the market portfolio.

Q. Please explain why you used CAPM only as a check on the reasonableness of your DCF analyses.

A. To perform a CAPM analysis, it is necessary to determine the return on a riskless asset, r, along with the appropriate beta and the appropriate rate of return on the market portfolio. Not surprisingly, there can be some difficulties in determining the appropriate beta, the appropriate riskless asset, and the effect of taxes. I use the CAPM results only as a check on my DCF analyses for this reason.

Additionally, the Commission has expressed a clear preference for DCF analyses in past Dockets. For example, in its May 8, 2015 Order in Docket No. E002/GR-13-868, a recent Northern States Power Company electric rate case, the Commission stated that the DCF model is the method "on which the Commission has historically placed its heaviest reliance."

Q. How did you initiate your CAPM analysis?

A. The first step consisted of selecting a reasonable riskless rate.

Q. Please discuss the riskless asset rate, r.

A. The yield on a 90-day Treasury bill is probably the best theoretical proxy for r. It is devoid of default risk and subject to a negligible amount of interest rate risk. But 90-day Treasury bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days. Thus, an equity investor that wants to invest in an asset yielding the risk free rate for a period comparable to the investor's stock holding period would face reinvestment risk, which is the risk that proceeds from the payment of principal and interest would have to be reinvested at a lower rate than the original investment, if the investor were to invest in 90-day Treasury bills.

While a 30-year Treasury bond, which is also generally considered to be devoid of default risk, may better match the equity investor's stock holding period, investing in a 30-year Treasury bond would subject the investor to significant interest rate risk, which, in a more general sense, is the risk associated with investment opportunities foregone because cash is tied up in investments made earlier. For example, if a person buys a 30-year Treasury bond carrying a six percent interest rate today, and a year later a new 30-year Treasury bond with a rate of seven percent is issued, then holding the original bond to maturity would cost this person the opportunity to earn seven percent interest, rather than six percent interest for the next 29 years. Thus, interest rate risk exists even when assets are held to maturity.

Q. Please provide the specific risk-free rate you used in your CAPM analysis.

A. As a means to balance the risks associated with short-term and long-term Treasuries, I used for purposes of the risk-free asset the average yield on 20-year Treasury bonds over the 30 trading days ending July 13, 2016, which is 1.95 percent. DOC Ex. ___ at JPK-4, Schedule 2 (Kundert Direct).

Q. Please discuss the market rate of return, k_m.

A. To determine the market rate of return, k_m, one first has to select a market portfolio. Common choices for the market portfolio include market indices such as the Standard & Poor's 500 (S&P 500), the Value Line Composite, or the New York Stock Exchange Index. The required return on that portfolio can be estimated once the specific market portfolio is selected.

Q. What did you select as your representative market portfolio?

A. I used the S&P 500 as a proxy for the market portfolio. The dividend yield for the S&P 500 was 2.05 percent as of July 27, 2016. DOC Ex. ___ at JPK-4, Schedule 4. Thomson provides five-year projected earnings share growth rate for the S&P 500 Index. As of May 26, 2016, this projected growth rate was 7.64 percent. DOC Ex. ___ JPK-4, Schedule 3 (Kundert Direct).[8] Similar to the dividend yields used in my DCF analysis, I applied a half years' worth of growth to this dividend yield, resulting in a dividend yield of 2.13 percent.

Using a DCF analysis, the required rate of return on the S&P 500 is 2.13 percent + 7.64 percent = 9.77 percent. I used this return as the market rate of return, k_m. DOC Ex. ___ at JPK-4, Schedule 1 (Kundert Direct).

[8] I was unable to source a five year projected earnings per share growth rate for the S&P Index as of July 15, 2016. The Department's source for this information was Yahoo Finance. Yahoo Finance no longer provides this information. The Department is attempting to acquire this information from Thomson/Reuters directly. I will update my testimony to include the projected five year earnings per share average growth rate for the S&P 500 as of July 15, 2016 if the Department is able to acquire this information in a timely fashion.

Q. What was the next step for the CAPM analysis?

A. I estimated beta, β, the systemic risk of the stock.

Q. What did you use as an estimate of beta for OTP?

A. I used estimates of beta for each of the companies in the DOC Comparable Group provided by Value Line. I used the average of these betas, or 0.75, as an estimate of beta for OTP. DOC Ex. ___ at JPK-4, Schedule 5 (Kundert Direct).

Q. Using these factors, what is your estimate of the average ROE for the DOC Comparable Group based on your CAPM analysis?

A. My CAPM estimate of the cost of equity for the DOC Comparable Group, included a 13-basis-point adjustment for flotation costs, is 7.91 percent.

Q. Is there a reasonable alternative method of applying the CAPM?

A. Yes. There are other versions of the CAPM that attempt to account for the deficiencies of the simple CAPM that I discussed above. One such model is the Empirical CAPM, or ECAPM.

Q. Please explain the ECAPM.

A. Various empirical studies have shown that, for companies with beta smaller than one, the simple CAPM results in a downward bias of the required rate of return compared to the theoretical CAPM. To explain this discrepancy, many studies postulated that there are other factors, besides beta, that may impact the systemic risk of a common stock. To capture the relationship between the ECAPM line and the theoretical CAPM line, ECAPM is expressed as follows:

$$K = r_f + a + \beta (k_m + r_f - a)$$

Where a is a fixed number and r + a represents the intercept of the ECAPM line.

Empirical studies have demonstrated that the ECAPM can be expressed as:[9]

$$K = r_f + 0.25(k_m - r) + 0.75\beta (k_m - r_f)$$

Q. What is the expected rate of return for the DOC Proxy Group using the ECAPM?

A. Using the same r_f (1.95 percent), β (0.75), and k_m (7.64 percent) as I used in the simple CAPM, the ECAPM results in a required return on equity of 8.28 percent. Once I include the flotation cost adjustment of 13 basis points, the expected rate of return is 8.41 percent.

Q. What do you conclude from your CAPM and ECAPM results?

A. I conclude that my ECAPM result falls within the ranges of my mean constant and two-growth DCF estimates. My CAPM result falls 22 and 19 basis points below the bottom of the ranges for my Constant and Two-Growth DCF models respectively. These CAPM results confirm the reasonableness of my DCF results.

---

[9] The ECAPM is obtained by estimating the linear relationship between the betas and the required rate of return. A good discussion of the ECAPM and related issues is provided by Roger A. Morin in his book: New Regulatory Finance, 2006 Chapter 6, pages 175 through 209.

E. RECOMMENDED RETURN ON EQUITY FOR OTP

Q. Based on your analysis, what do you conclude is a reasonable rate of return on common equity capital for OTP?

A. My recommended reasonable ROE of 8.87 percent is the specific value that I recommend based on the results of my two-growth DCF and including a flotation cost adjustment. As noted above, the DCF is a fair, market-oriented method that uses current, relevant information to allow OTP to compete sufficiently and fairly in the capital markets and thus I rely on my DCF results to determine the reasonable rate of return of common equity capital for OTP. I did not identify a range of ROEs that could be viewed as reasonable estimates for OTP.

Q. Do you plan to update your recommendation in your future testimony in this rate case?

A. Yes, I intend to update this recommendation using the most up-to-date market information available when I file my Surrebuttal testimony.

V. THE CAPITAL STRUCTURE, COSTS OF SHORT- AND LONG-TERM DEBT AND THE COST OF CAPITAL FOR OTP

A. CAPITAL STRUCTURE

Q. What capital structure has OTP proposed to use in this rate case?

A. OTP Witness Kevin Moug discusses the Company's proposed capital structure for the 2016 test year, which is summarized in Table 7.

Table 7 OTP Proposed 2016 Test Year Capital Structure			
Component	Proposed Capital Structure	Proposed Cost	Weighted Cost of Capital
	[1]	[2]	[3] = [1] x [2]
Long-term Debt	44.90%	5.62%	2.52%
Short-term Debt	2.60%	3.28%	0.09%
Common Equity	52.50%	10.40%	5.46%
Total	100.00%		8.07%
Source:			
Exhibit No. ___ (KGM-1), Schedule 2, Revised May 25, 2016			

Q. Why is it necessary to determine a reasonable capital structure for OTP?

A. OTP's overall cost of capital is the average of the costs of long-term debt, short-term debt, and common equity that OTP faces, weighted by the amount of each type of financing that the Company uses. Thus, to arrive at the cost of capital (the overall rate of return) for OTP it is necessary to determine reasonable ratios of long-term debt, short-term debt and common stock equity that the Company uses as sources of financing.

Q. Does OTP have its own capital structure apart from OTC's' capital structure?

A. Yes. As described on page 5 of Mr. Moug's Direct Testimony, OTP maintains separate senior unsecured debt ratings from the three major ratings agencies apart from OTC. It also maintains its own short-term debt mechanism via a multi-year credit facility. As such, its capital structure can be considered as actual or predominately market-based.

Q. How do you assess the reasonableness of OTP's proposed capital structure?

A. It is a well-accepted premise in finance that there exists an optimal capital structure that minimizes the overall cost of capital, for each company. However, there is no simple way to analytically determine a company's optimal capital structure. Therefore, I assessed the reasonableness of OTP's proposed capital structure by comparing it to the capital structures of the companies in the DOC Comparable Group. If OTP's proposed capital structure is comparable to those of its risk-comparable peers, we may conclude that OTP's capital structure is reasonable. Table 8 presents selected summary statistics of the capital structures of the members of the DOC Proxy Group and compares OTP's proposed capital structure ratios to them.

Q. What criteria did you adopt to determine the reasonableness of OTP's proposed capital structure?

A. I developed a range for each component of the Department Proxy Group's (DPG) 2015 average capital structures that added and subtracted one standard deviation from the DOC Comparable Group average for each of the capital structure components. DOC Ex. ___ at JPK-5, Schedule 1 (Kundert Direct).

Q. What is the basis for your decision that a range of the average plus or minus one standard deviation is an appropriate measure of reasonableness for OTP's proposed capital structure?

A. The average of a set of data values is a measure of the central tendency. The standard deviation provides a measure of the amount of variation or dispersion within a set of data values. If the data values in the set are normally distributed, the range I have identified should incorporate a little more than 68 percent of the values included in the data set. To my way of thinking, a range developed on that basis could be defined as reasonable.

Q. Please compare OTP's proposed capital structure to the ranges you developed for the companies in the DOC Proxy Group.

A. OTP's proposed equity ratio of 52.50 percent is 7.13 percentage points higher than the DOC Comparable Group average equity ratio of 45.37 percent and 1.18 percentage points higher than the average plus one standard deviation for common equity of 51.32 percent. The Company's proposed long-term debt ratio is 6.36 percentage points lower than the DOC's Comparable Group's average long-term debt ratio of 51.26 percent and 0.68 percentage points lower than the average minus one standard deviation for long-term debt of 45.58 percent. OTP's proposed short-term debt ratio is 0.59 percentage points lower than the DOC Comparable Group's average short-term debt ratio, but at 2.60 percent it does fall within a range of the average plus or minus one standard deviation or 0.98 to 5.39 percent. Table 8 summarizes this information in DOC Ex. ___ at JPK-5, (Kundert Direct).[10]

Table 8
DOC Comparable Group Year-End Capital Structures for 2015
and Comparison to OTP's Proposed 2016 Capital Structure

Company	Stock Ticker	Short-Term Debt Ratio	Long-Term Debt Ratio	Preferred Stock Ratio	Common Equity Ratio	Total
ALLETE Inc.	ALE	0.05%	46.84%	0.00%	53.12%	100.00%
American Electric Power	AEP	2.07%	51.59%	0.00%	46.34%	100.00%
Ameren Corp	AEE	2.05%	49.61%	0.97%	47.37%	100.00%
Avista Corp	AVA	3.22%	49.86%	0.00%	46.91%	100.00%
CMS Energy Corp	CMS	1.85%	68.69%	0.27%	29.19%	100.00%
DTE Energy Co	DTE	2.69%	50.10%	0.00%	47.21%	100.00%
El Paso Electric Co	EE	6.18%	49.48%	0.00%	44.34%	100.00%
Northwestern Corp	NWE	6.31%	49.73%	0.00%	43.96%	100.00%
PG&E Corp	PCG	2.99%	47.57%	0.74%	48.70%	100.00%
PNM Resources Inc	PNM	6.25%	52.18%	0.29%	41.28%	100.00%
Portland General Electric Co	POR	0.13%	49.33%	0.00%	50.54%	100.00%
Scana Corp	SCG	4.44%	50.10%	0.00%	45.46%	100.00%
Average		3.19%	51.26%	0.19%	45.37%	100.00%
Standard Deviation		2.21%	5.68%	0.33%	5.95%	
Avg. Less One Std. Dev.		0.98%	45.58%	-0.14%	39.41%	
Avg. Plus One Std. Dev.		5.39%	56.93%	0.52%	51.32%	
OTP Proposed 2016 Capital Strucutre		2.60%	44.90%	0.00%	52.50%	100.00%
Does OTP's Proposed % Fall Within One Std. Dev. Of DCG Average?		Yes	No	Yes	No	

[10] OTP does not have any preferred stock, so that ratio is set equal to 0.00 percent. Interestingly, that value falls within the range of 0.00 to 0.52 percent identified in Table 8 as well.

Q. Is the capital structure OTP proposed reasonable?

A. The above analysis suggests that it is not reasonable. The common equity ratio is unreasonably high and the long-term debt ratio is unreasonably low. The short-term debt ratio does appear reasonable however.

However, other than for CenterPoint Energy, as a condition of approval of that utility's merger, I am not aware of the Commission using hypothetical capital structures to determine the overall rate of return in rate cases. Thus, while I provide the above information for this record, I do not at this time recommend that the Commission impute a capital structure in setting OTP's overall ROR. Instead, I recommend that OTP fully explain in its rebuttal testimony why it would be reasonable to require its ratepayers to pay rates based on an equity ratio that is much higher than the equity ratio of the DOC Comparable Group.

B. THE COSTS OF SHORT- AND LONG-TERM DEBT

Q. Please discuss the Company's proposed short-term debt costs.

A. OTP Ex. ___ at KGM-1, Schedule 5 (Moug Direct), Revised May 25, 2016, provides the Company's calculations of its short-term cost of debt for the test year. The Company's proposed test-year cost of short-term debt is 3.28 percent which is the 13-month average over the period December 1, 2015 through December 31, 2016. The cost of short-term debt consists of two components: interest expense and monthly fees for the short-term credit facility.

Q. Please explain more about OTP's short-term debt.

A. OTP is party to a multi-year credit agreement (MYCA) with several banks. OTP pays a fixed monthly service fee plus interest on any actual money borrowed under the MYCA. OTP forecasts the cost associated with this component of the MYCA to be $319,712 and the rate for the service fee portion of the MYCA to be 1.25 percent during the test year. The Company estimates the interest rate associated with monthly interest expense portion of the MYCA to be 2.04 percent. Adding the above two rates results in a test-year short-term debt cost of 3.28 percent. OTP Ex. ___ KGM-1, Schedule 5 (Moug Direct).

Q. Is the Company's proposed method for calculating its cost of short-term debt reasonable?

A. Yes, since it appropriately reflects OTP's two sources of short-term financing. Further, I asked OTP to update its forecast for its short-term debt rate in DOC Information Request No. 217. The Company's most recent estimate is 2.89 percent. This new estimate is 39 basis points lower than its previous estimate of 3.28 percent. I included a copy of DOC Information Request No. 217 as DOC Ex. ___ at JPK-6 (Kundert Direct).

Q. Are you proposing to update OTP's short-term cost of debt to include this information in your Direct Testimony?

A. No. I prefer to wait to update OTP's short-term cost of debt until Surrebuttal testimony given that it is a market-based estimate. The use of this approach will provide the Commission with the best estimate in this proceeding.

Q. Please discuss OTP's proposed long-term debt cost.

A. OTP Ex. ___ at KGM-1, Schedule 4 (Moug Direct) provides the calculation of OTP's cost of long-term debt. These calculations are based on 13-month average over the period December 1, 2015 through December 31, 2016, and result in the test-year cost of long-term debt of 5.62 percent.

Q. How is this cost of 5.62 percent of long-term debt determined?

A. The cost reflects seven outstanding loans currently in effect.

Q. Is the Company's proposed cost of long-term debt of 5.62 percent reasonable?

A. Yes, since it reasonably reflects OTP's current long-term debt costs. Similar to the Company's estimate of its short-term debt, I asked OTP to update its cost of long-term debt in DOC Information Request No. 216.[11] I also asked OTP to explain why it had not attempted to retire three of its outstanding debt issuances given that this debt's relatively short remaining duration and the current market rates for short-term debt in DOC Information Request No. 219.

Q. Did OTP explain its rationale for not retiring those debt issuances?

A. Yes. Apparently the three issuances all have "make whole" provisions. The Company provided an analysis that demonstrated that the addition of the "make-whole" payment would increase OTP's refinancing costs to the extent that refinancing the debt was no longer cost-effective.[12]

---

[11] A copy of the information request is included as DOC Exhibit No. ___ at JPK-7.
[12] A copy of DOC Information Request No. 219 is included as DOC Exhibit No. ___ at JPK-8.

Q. Are you proposing to update OTP's long-term cost of debt to include this information in your direct testimony?

A. No. I will update OTP's long-term cost of debt in my Surrebuttal Testimony along with the other cost-of-capital components.

C. THE COST OF CAPITAL FOR OTP

Q. What is your recommendation regarding the cost of capital (overall rate of return) for OTP?

A. Based on my recommendations of return on equity of 8.86 percent, short-term debt cost of 3.28 percent, and long-term debt cost of 5.62 percent, my recommended cost of capital for OTP is shown in CORRECTED Table 9 below.

CORRECTED - Table 9
DOC Proposed
2016 Test Year Capital Structure

Component	Proposed Capital Structure	Proposed Cost	Weighted Cost of Capital
	[1]	[2]	[3] = [1] x [2]
Long-term Debt	44.90%	5.62%	2.52%
Short-term Debt	2.60%	3.28%	0.09%
Common Equity	52.50%	8.87%	4.66%
Total	100.00%		7.27%

VI. RESPONSE TO THE TESTIMONIES OF THE COMPANY'S WITNESSES

Q. To which Company's witness do you respond?

A. The Company sponsors two witnesses testifying on rate of return issues. I respond to the Direct Testimony of the Company's witness Mr. Robert B. Hevert on the rate of return. I also respond to Mr. Kevin G. Moug's Direct Testimony regarding the appropriate capital structure for OTP.

A. DISCUSSION OF COMPANY WITNESS ROBERT B. HEVERT'S TESTIMONY

Q. Please summarize Mr. Hevert's conclusions regarding the required rate of return on equity.

A. Based on his DCF, CAPM and Bond Yield Plus Risk Premium (RP) analyses Mr. Hevert recommends a rate of return on equity of 10.40 percent.

Q. Do you agree with Mr. Hevert's recommendation?

A. While I agree with many aspects of his testimony, I do not agree that his final ROE recommendation was shown to be reasonable under current market conditions. Below, I describe my disagreements with the following:

1. Mr. Hevert's proxy group screening criteria;
2. The risk-free rate he used in his CAPM analyses;
3. His bond yield plus risk premium analyses;
4. His proposed ROE adjustments for OTP's high level of forecasted capital expenditures, small size and customer concentration;
5. The ROE incentive adjustment he proposes;
6. His reliance on the CAPM and bond yield plus risk premium analysis in developing his recommended ROE; and

7. His analysis that concludes that OTP's proposed capital structure is appropriate.

Q. Do you agree with Mr. Hevert's screening criteria?

A. I agree with some of his screening criteria, but not with all of them. I also disagree with his application of some of the screening criteria that we both use.

Q. Which of the screening criteria do you consider to be unreasonable?

A. I disagree with Mr. Hevert's use of "Companies with a market capitalization of less than $10 billion (small-cap); and "Companies less than 250 customers per square mile" screening criteria. These screening criteria exclude companies with a market capitalization of more than $10 billion and companies with customer densities greater than 250 customers per mile. OTP Ex. ___ at 10-13 (Hevert Direct).

Q. Please list the screening criteria that you believe have been misapplied.

A. These criteria include the "regular payment of cash dividends", the "maintains an unsecured bond and/or corporate credit rating from S&P", the "currently known to be party to a merger or some other significant transaction", and the "exclusion of companies with mean DCF results of less than 8.00 percent" screens.

Q. How did you address your concerns with the screening criteria Mr. Hevert used?

A. I evaluated the different screening criteria consistent with the Company's response to DOC Information Request No. 203, DOC Exhibit No. ___ at JPK-9 (Kundert Direct).

Q. What is the first screening criterion the Company addresses in its response to DOC IR No. 203?

A. The first criterion is the "consistently pays quarterly dividends" screen.

Q. What is your concern regarding Mr. Hevert's application of this screening criterion?

A. I believe that Mr. Hevert inappropriately excluded El Paso Electric Company from OTP's Proxy Group due to his application of this screen.

Q. Please continue.

A. In subpart (b) of DOC IR No. 203 the Department asked Mr. Hevert to identify the time period this criterion covered (e.g. most recent quarter, most recent annual reporting period) as well as the list of companies eliminated by this screen. Mr. Hevert explained in his response that he did not consider a specific timeframe regarding the payment of dividends but considered two criteria when evaluating companies using this criterion – (1) the company must display a sufficient history of quarterly dividend payments such that investors' expectations can be based on consistent quarterly dividend payments; and (2) the company has not recently decreased its quarterly dividend payment. He also noted that El Paso Electric was the only company eliminated by this screen.

Q. What is the basis of your disagreement with Mr. Hevert's application of this screening criterion?

A. According to El Paso Electric Company's website, it has paid consistent quarterly dividends for the past five years (June 30, 2011 through June 30, 2016).[13] El Paso is also scheduled to pay a quarterly dividend on September 30, 2016. As a result, I believe five years of quarterly dividend payments represents a sufficient history of quarterly dividend payments and that Mr. Hevert erred by removing El Paso Electric from the OTP Proxy Group.

Q. What about Mr. Hevert's second criterion – a recently decreased quarterly dividend payment?

A. I reviewed the Value Line (VL) one page summary for El Paso Electric dated April 29, 2016, DOC Exhibit No. ___ at JPK-10 (Kundert Direct). VL stated at that time that it forecasted higher profits for El Paso in 2017 and was forecasting an increase in the dividend of 5.1 percent effective in June 2016. El Paso's board of directors did raise its quarterly dividend payable in June 2016 by roughly that percentage. This information suggests that El Paso Electric doesn't fulfill Mr. Hevert's second criterion – that being decreasing dividend payments either.

Q. Does El Paso Electric have a history of unusual or erratic dividend payments?

A. Yes, it has to some extent. It didn't pay a common stock dividend from 1989 through June 30, 2011.

Q. Would the fact that El Paso Electric didn't pay dividends at some point in the past be sufficient grounds to exclude it from the DOC's Proxy Group?

[13] See http./ir.epelectric.com/dividends.com

A. No. The DCF is a forward looking model. That fact combined with Value Line's assessment of the company's future dividends means that it would be inappropriate to eliminate El Paso Electric from this analysis.

Q. Did you evaluate the effect of including El Paso Electric in OTP's proxy group?

A. Yes, I did.

Q. Please describe your analysis.

A. To estimate the effects of each of Mr. Hevert's different screens on the average ROE using the Department's Constant and Two-Growth DCF models, I developed an iteration of those models that included OTP's Proxy Group and updated the share price information through July 15, 2016. I call this scenario the OTP Base Case.

Q. What are the results of that analysis?

A. The mean in the OTP Base Case for the Constant DCF analysis is 9.05 percent without accounting for flotation costs. The mean result for the Two-Growth DCF is 8.89 percent, also without accounting for flotation costs. REVISED DOC Exhibit No. ___ at JPK- 11, UPDATED Schedules 1 and 2 (Kundert Direct) contain these analyses.

Q. What is the result of including El Paso Electric in the OTP Proxy Group on the average ROE you identified for the Constant Growth and Two-Growth Growth DCF models in the Base Case scenario?

A. The mean for the Constant DCF analysis decreases by 25 basis points to 8.80 percent (without accounting for flotation costs). The mean result for the Two-Growth DCF also declines by 24 basis points to 8.65 percent (also without accounting for flotation costs). REVISED DOC Exhibit No. ___ at JPK- 11, UPDATED Schedules 3 and 4 (Kundert Direct) contain these analyses.

Q. What is your conclusion regarding Mr. Hevert's application of the "consistently pays quarterly dividends" screening criterion?

A. My conclusion is that Mr. Hevert misapplied the screening criterion and unreasonably excluded El Paso Electric Company from further consideration for inclusion in the OTP Proxy Group.

Q. What is the next screening criterion that merits attention?

A. The second is the "must maintain an unsecured bond and/or corporate credit rating from S&P of BBB "screening criterion discussed in subpart (d) of the Company's response to DOC IR No. 203.

Q. Please explain the basis for your concern with this screening criterion.

A. Mr. Hevert's screen is asymmetric. It only eliminates companies that are one credit rating level *below* OTP's level of BBB. It does not do the same for companies whose credit ratings may be more than one rating level *above* OTP's. As a result, it allows for the inclusion of companies with credit ratings and risk profiles that differ by more than one rating level from OTP's.

Q. Did Mr. Hevert's use of this asymmetric screening criterion eliminate any companies?

A. No, it did not. However, the use of a symmetrical screen (BBB- to BBB+) would have eliminated one of the companies included in Mr. Hevert's comparable group - Alliant Energy Resources Corp (LNT).

Q. Did you evaluate the effect of applying this screening criterion on a symmetrical basis and by extension, removing Alliant from OTP's proxy group?

A. Yes, I did.

Q. What is the result of applying a symmetrical credit rating screen on the OTP Base Case average ROEs you identified for the Constant Growth and Two-Growth Growth DCF models?

A. The mean for the Constant DCF analysis decreases by 3 basis points to 9.02 percent (without accounting for flotation costs). The mean result for the Two-Growth DCF declines by 5 basis points to 8.84 percent (again without accounting for flotation costs). REVISED DOC Exhibit No. ___ at JPK- 11, CORRECTED Schedules 5 and 6 (Kundert Direct) contain these analyses.

Q. What is your conclusion regarding Mr. Hevert's application of this screening criterion?

A. My conclusion is that Mr. Hevert misapplied the "must maintain an unsecured bond and/or corporate credit rating from S&P of BBB-" screening criterion and unreasonably included Alliant Energy in OTP's Proxy Group.

Q. What is the next screening criterion that merits attention?

A. The third is the "$10 billion market capitalization" screening criterion discussed in subpart (h) of the Company's response to DOC IR No. 203.

Q. Previously in this testimony you identified this screening criterion as being unreasonable - can you explain that earlier statement?

A. Yes. It appears that Mr. Hevert is making an implicit “small size” argument by including this screening criterion and the apparently randomly selected threshold of $10 billion in capitalization. While a company’s size does affect its risk profile, my position is that this factor is considered and evaluated by the different ratings agencies and is subsumed in the company’s credit rating. The appropriate use of a symmetrical corporate credit rating screening criterion eliminates the need for this screening criterion.

Q. Please discuss the “$10 billion market capitalization” effect on the OTP proxy group.

A. The “$10 billion market capitalization” screen eliminated four companies – (1) American Electric Power (AEP), Dominion Resources (D), DTE Energy Company (DTE) and Xcel Energy, Inc. (XEL) from further consideration.

Q. Did you extend the “Base Case” scenario you developed to include the companies that were excluded due to the “$10 billion market capitalization” screen?

A. Yes, I did to the extent I could due to requirements associated with other screening criteria. I included three of the four companies – AEP, DTE and XEL. I didn’t include Dominion Resources due to the fact that it is attempting to combine with Questar Corporation. As a result, it no longer meets the “not party to a merger or other transformative” criterion.

Q. What are the results of the DCF models if you include the three companies that Mr. Hevert excluded due to the “$10 billion market capitalization” screen?

A. The average ROE for the Constant DCF declines by 23 basis points to 8.82 percent. The average ROE the Two-Growth DCF declines by 20 basis points to 8.69 percent. REVISED DOC Exhibit No. ___ at JPK- 11, CORRECTED Schedule 7 and UPDATED Schedule 8 (Kundert Direct) contain these analyses.

Q. What is your conclusion regarding Mr. Hevert's use of this screening criterion?

A. My conclusion is that Mr. Hevert should not have used this screening criterion and that American Electric Power, DTE Energy Company and Xcel Energy Inc. were unreasonably excluded from further consideration for inclusion in OTP's Proxy Group.

Q. What is the next screening criterion that concerns you?

A. The fourth is the "customer density "screening criterion discussed in subpart (i) of the Company's response to DOC IR No. 203.

Q. Please discuss the "customer density" screening criterion.

A. Customer density is one of many factors that may affect a utility's business risk. However, there are many factors that may impact a utility's business risk, such as rate design, customer mix, weather pattern, regulatory treatment of various issues and other factors as well. There is no reason to single out just one of these factors to screen companies. Instead, overall risk measures that reflect all aspects of business risk should be used to select the reasonable comparison group.

Q. Did the use of the "customer density" screening criterion result in the inappropriate elimination of some utilities?

A. Yes, both Pinnacle West Capital Corp (PNW) and Portland General Electric Company (POR) wouldn't have excluded from further consideration if this screening criterion had not been utilized according to information included in the Company's response to DOC IR No. 203.

Q. Have you performed an analysis that evaluates the impact of the addition of those two companies on the DOC's OTP Base Case?

A. Yes, I have.

Q. What are the results of the DCF models if you include the two companies that Mr. Hevert excluded due to the "customer density" screen?

A. The average ROE for the Constant DCF model declines 17 basis points to 8.88 percent. The average ROE for the Two-Growth DCF declines 9 basis points to 8.80 percent. REVISED DOC Exhibit No. ___ at JPK- 11, UPDATED Schedule 9 and CORRECTED Schedule 10 (Kundert Direct) contain these analyses.

Q. What is your conclusion regarding Mr. Hevert's use of this screening criterion?

A. My conclusion is that Mr. Hevert should not have used this screening criterion and that Pinnacle West Capital Corporation and Portland General Electric Company should not have been excluded from further consideration for inclusion in OTP Proxy Group on the basis of this screening criterion.

Q. What is the next screening criterion that concerns you?

A. The fifth criterion is the "currently known to be a party to a merger or some other significant transaction" screening criterion discussed in subpart (j) of the Company's response to DOC IR No. 203.

Q. Please explain the basis for your concern with this screening criterion.

A. I agree that the criterion is appropriate, but Mr. Hevert appears to have misapplied this criterion and unreasonably excluded three companies from further consideration.

Q. Please continue.

A. According to the information included in the Company's response to DOC IR No. 203, Mr. Hevert excluded the following three companies using this criterion even though none of the three are involved in a "merger or some other significant transaction" as far as the Department can determine:

- Edison International (EIX) was excluded due to the "bankruptcy of merchant generation business and ongoing payments associated with settlement".
- Entergy Corporation (ETR) was excluded due to "negative consensus growth rates; nuclear impairments expected".
- Pacific Gas and Electric (PCG) was excluded due to "material effect on earnings from San Bruno accident, including fines and lawsuits".

Q. Wouldn't you agree that the descriptions of the financial problems listed in the Company's response represent significant financial burdens for the three companies in question?

A. Yes, I agree that these three companies appear to be stressed financially. However, I don't believe they should have been excluded from OTP Proxy Group on the basis of a "merger or significant transaction" screening criterion. The basis for this screening criterion is that once a company is party to a merger or acquisition, its stock price is predominantly influenced by the effects of that specific transaction. As a result, it is reasonable to exclude that company from a comparable group. However, the reasons Mr. Hevert listed for excluding EIX, ETR and PCG are not related to those companies share prices being influenced by a merger or acquisition. Rather, those companies were excluded due to adverse financial conditions whose effects should be recognized in the companies' respective stock prices. The fact that a company may be experiencing financial difficulties doesn't preclude it from being included in a comparable group if it meets the necessary screening criteria.

Q. Have you performed an analysis that evaluates the impact of the addition of those three companies on the DOC's OTP Base Case?

A. Yes, I have.

Q. What are the results of the DCF models if you include the three companies that Mr. Hevert excluded due to the "merger or some other significant transaction" screen?

A. The average ROE for the Constant DCF model declines 54 basis points to 8.51 percent. The average ROE for the Two-Growth DCF declines 21 basis points to 8.68

percent. REVISED DOC Exhibit No. ___ at JPK- 11, CORRECTED Schedule 11 and UPDATED Schedule 12 (Kundert Direct) contain these analyses.

Q. What is your conclusion regarding Mr. Hevert's use of this screening criterion?

A. My conclusion is that Mr. Hevert misapplied this screening criterion and that Edison International, Entergy Corporation and Pacific Gas and Electric should not have been excluded from further consideration for inclusion in OTP's proxy group on the basis of this screening criterion.

Q. What is the next screening criterion that concerns you?

A. The sixth criterion is the "8.00 percent minimum financial reasonableness" screening criterion discussed in subpart (k) of the Company's response to DOC IR No. 203.

Q. Please explain the basis for your concern with this screening criterion.

A. Mr. Hevert's appears to have misapplied this criterion and unreasonably excluded three companies – IDACORP, Westar Energy Inc. and OGE Energy Corp -- from further consideration for inclusion in the OTP proxy group on the basis of this criterion.

Q. Why do you believe Mr. Hevert misapplied this screening criterion?

A. Mr. Hevert identifies the 8.00 percent minimum screening criterion as some sort of administratively determined threshold. As noted earlier in this testimony, the Department bases the level of this threshold on market information. The current market information, discussed above, identifies 7.00 percent as the reasonable threshold. As a result, Mr. Hevert misapplied this criterion.

Q. Have you performed an analysis that evaluates the impact of the addition of those three companies on the DOC's OTP Base Case?

A. Yes. Great Plains Energy Inc. announced plans to acquire Westar Energy Inc. recently. As a result, I removed Westar Energy from the analysis on the basis of the "party to a merger" screening criterion. Thus, I performed an analysis that included both IDACORP and OGE Energy Corp to the OTP Base Case.

Q. What are the results of the DCF models if you include the three companies that Mr. Hevert excluded due to the "8.00 percent minimum financial reasonableness" screen?

A. The average ROE for the Constant DCF model declines 43 basis points to 8.62 percent. The average ROE for the Two-Growth DCF declines 35 basis points to 8.54 percent. REVISED DOC Exhibit No. ___ at JPK- 11, UPDATED Schedule 13 and CORRECTED Schedule 14 (Kundert Direct) contain these analyses.

Q. What is your conclusion regarding Mr. Hevert's use of this screening criterion?

A. My conclusion is that Mr. Hevert misapplied this screening criterion and that IDACORP, OGE Energy Corp and Westar Energy Inc. should not have been excluded from further consideration for inclusion in OTP's proxy group on the basis of this screening criterion. Further review concluded that Westar Energy Inc. should be excluded from the OTP proxy group due to merger activity however.

Q. Please summarize the results of your analysis of the screening criteria used to select OTP's Proxy Group.

A. Mr. Hevert misapplied four screening criteria – (1) consistent dividends, (2) credit ratings, (3) party to a merger or acquisition and (4) 8.00 percent minimum average DCF. In addition, he used two screening criteria that were unnecessary given the use of the credit rating criterion – (1) $10 billion market capitalization and (2) customer density is greater than 250 per square mile.

The misapplication or use of these inappropriate screening criteria eliminated 13 electric utilities that should not have been removed from further consideration on the basis of those criteria. He also included one electric utility that should have been excluded if the credit rating criterion had been correctly applied. Table 10 lists the affected companies. It also references those same companies' status in the DOC Proxy Group where "not applicable" (n/a) indicates that the respective company is included in the DOC Proxy Group. Thus, the Department identified the following five companies out of the fourteen as being inappropriately excluded from OTP's Proxy Group – (1) American Electric Power, (2) DTE Energy Company; (3) El Paso Electric Company; (4) Pacific Gas and Electric, and (5) Portland General Electric. These five companies are included in the DOC Proxy Group.

Table 10 Comparison of Companies Excluded from OTP Proxy Group and Current Status of those Companies in DOC Proxy Group			
Line No.	Company	Included in DOC Proxy Group	Basis for Exclusion from DOC Proxy Group
1.	Alliant Energy Corp	No	Credit rating outside range
2.	American Electric Power	Yes	n/a
3.	Dominion Resources	No	Merger activity
4.	DTE Energy Company	Yes	n/a
5.	Edison International	No	Minimum ROE
6.	El Paso Electric Company	Yes	n/a
7.	Entergy Corp	No	Minimum ROE
8.	IdaCorp	No	Minimum ROE
9.	OGE Energy Corp	No	Credit rating outside range
10.	Pacific Gas & Electric	Yes	n/a
11.	Pinnacle West Capital Corp	No	Credit rating outside range
12.	Portland General Electric Company	Yes	n/a
13.	Westar Energy Inc	No	Merger activity
14.	Xcel Energy Inc.	No	Credit rating outside range

Q. What is your conclusion regarding the information contained in Table 10?

A. I conclude that Table 10 and the analysis above not only identifies the inappropriateness of Mr. Hevert's comparable group, but also supports the reasonableness of the DOC Proxy Group.

Q. Please explain.

A. The DOC Proxy Group contains 12 companies. The OTP Proxy Group currently contains 8 companies.[14] The two proxy groups have seven companies in common.

[14] Great Plains Energy has been removed from the OTP Proxy Group due to its ongoing merger. See OTP's response to DOC IR No. 203.

All five of the companies included in the DOC Proxy Group, but not included in the OTP Proxy Group are included in Table 10. Table 11 summarizes this information.

Table 11		
Proxy Group Comparison		
Line No.	Description	Ticker
	Companies Common to Both DOC and OTP Proxy Groups	
1.	Allete Inc	ALE
2.	Ameren Corp	AEE
3.	Avista Corp	AVA
4.	CMS Energy Corp	CMS
5.	Northwestern Corp	NWE
6.	PNM Resources Inc	PNM
7.	Scana Corp	SCG
	Companies Included in DOC Proxy Group and Inappropriately Excluded from OTP Proxy Group	
8.	American Electric Power	AEP
9.	DTE Energy Company	DTE
10.	El Paso Electric Company	EE
11.	Pacific Gas & Electric	PCG
12.	Portland General Electric Company	POR
	Companies Included in OTP Proxy Group and Not in DOC Proxy Group	
13.	Alliant Energy Corp	LNT
14.	Great Plain Energy	GXP

Q. Do you have any additional comments on Mr. Hevert's use of two of the screening criteria you have identified as inappropriate - $10 billion in market capitalization and customer density is greater than 250 per square mile?

A. Yes. My opinion is that the risks associated with OTP's small size and low level of customer density are incorporated in the development of the Company's credit rating. The fact that both Mr. Hevert and I used OTP's credit rating from S&P as a basis for developing our respective proxy groups means that these risks have been incorporated into the analysis of OTP's cost of equity. When Mr. Hevert then essentially reapplied these two criteria to the Value Line group of electric utilities that have survived his earlier screening criteria, he unreasonably skewed the selection process for the OTP Proxy Group towards selecting companies with higher risk profiles, and presumably higher costs of equity. The lower average ROEs identified for the different scenarios in my analysis supports this assertion. This is the basis for my conclusion that the use of these two screening criteria is inappropriate.

Q. Do you have any additional comments on Mr. Hevert's apparent misapplication of the four screening criteria you identified?

A. Yes. I modeled the effects of including the companies Mr. Hevert had excluded inappropriately from the OTP Proxy Group on the basis of those criteria in DOC Ex. __ at JPK-11. My results suggest that if Mr. Hevert hadn't excluded a particular company or set of companies on the basis of those screening criteria, the mean ROE for the modified OTP Proxy Group would have been lower than it was for the original OTP Proxy Group in each scenario.

I also performed this exercise for the one company that Mr. Hevert included inappropriately in the OTP Proxy Group. The exclusion of that company from the OTP Proxy Group lowered the modified OTP Proxy Group's mean ROE in that instance as well. CORRECTED Table 12 summarizes this information.

CORRECTED - Table 12 Comparison of OTP Proxy Group to DOC Additions/Deletions Using DOC Two-Stage Model Results and Market Information as of July 15, 2016 Excluding Flotation Costs				
Line No.	Description	Mean ROE	Difference from Base Case Mean ROE	Changes to OTP Proxy Group
1.	OTP Base Case	8.89%	Not Applicable	
	DOC Scenarios			
2.	Consistent Dividend	8.65%	-0.24%	El Paso Electric included
3.	Symmetrical Bond Rating	8.84%	-0.05%	Alliant Energy excluded
4.	Less than $10 Billion Market Cap	8.69%	-0.20%	American Electric Power, DTE Energy and Xcel Energy Inc. included
5.	Customer Density Less than 250/sq mile	8.80%	-0.09%	Pinnacle West Capital Corp and Portland General Electric Company included
6.	Merger or Other Significant Transaction as of the Filing Date	8.68%	-0.21%	Edison International, Entergy Corp, and Pacific Gas and Electric included
7.	8.00 Percent Minimum ROE	8.54%	-0.35%	IdaCorp and OGE Energy included

Q. Are all the companies you identified as being unreasonably excluded from OTP's Proxy Group in this analysis included in the DOC's Proxy Group?

A. No. Six of the eleven companies I identified as being unreasonably excluded from OTP's Proxy Group (Edison International, Entergy Corp, IdaCorp, OGE Energy, Pinnacle West Capital Corp, and Xcel Energy Inc) were eliminated from the DOC Proxy Group due to other screening criteria. The five companies unreasonably excluded from the OTP Proxy Group and included in the DOC Proxy Group include American Electric Power, DTE Energy Corp, El Paso Electric, Pacific Gas and Electric and Portland General Electric Company.

Q. How would one determine the extent of the effect of the inclusion or exclusion of companies from the OTP Proxy Group given that your analysis only considers the effects of the screening criteria individually?

A. One could use the Department's DCF models and then compare the mean ROEs between the OTP Proxy Group and the DOC Proxy Group as of the same date, while using the same number of trading days that are averaged over the period in question.

Q. Did you perform this comparison?

A. Yes, I took information from REVISED DOC Exhibit Nos. ___ at JPK-3 and at JPK-11 that both included pricing information as of July 15, 2016 and 30 days of pricing information. Table 13 contains this information.

CORRECTED - Table 13 Comparison of DCF ROE Results For OTP and DOC Proxy Groups			
Model	**OTP**	**DOC**	**Difference**
Constant Growth DCF	9.05%	8.89%	0.16%
Two-Growth DCF	8.89%	8.74%	0.15%
Sources:			
REVISED DOC Ex. ___ JPK-3, Schedules 1-2 (Kundert Direct)			
REVISED DOC Ex. ___ JPK-11, Schedules 1-2 (Kundert Direct)			

Q. What is the difference between the mean ROE's for the OTP Proxy Group and DOC Proxy Groups if one updates the Department's models to incorporate price and growth rates as of July 15, 2016?

A. The difference for the Constant Growth DCF models is 16 basis points. The OTP Proxy Group's Constant Growth ROE is 9.05 percent. The DOC Proxy Group's

Constant Growth's ROE is 8.89 percent. The difference for the Two-Growth models is 15 basis points. The OTP Proxy Group's Two Growth ROE is 8.89 percent. The DOC Proxy Group's Two-Growth model's ROE is 8.74 percent.

Q. What is your conclusion given this information?

A. My conclusion is that the development of a reasonable proxy group is important and necessary in that it may result in a decrease for a company's ROE of 15 or 16 basis points.

B. MR. HEVERT'S DCF ANALYSIS

Q. Please discuss Mr. Hevert's constant growth rate DCF analyses.

A. Mr. Hevert, performed three constant growth rate DCF analyses. As noted above, the constant growth rate DCF model requires the analyst to estimate a dividend yield and growth rate for each company included in the analysis. OTP Ex. ___ at 15-20 (Hevert Direct).

Mr. Hevert developed three estimates of dividend yield for each member of his proxy group, calculated with the average closing stock prices over the 30-, 90- and 180-trading-day periods ending December 15, 2015. In his DCF analyses, Mr. Hevert also applied a half years' worth of growth to each dividend yield, as I did. For growth rates, Mr. Hevert used estimates from the same three investor services I used (Thomson, Value Line, and Zacks).

For each estimated dividend yield, Mr. Hevert estimated the required rate of return using the minimum, maximum, and average of the three growth rates.

Q. Do you agree with Mr. Hevert's calculations of the dividend yields?

A. I agree with Mr. Hevert's approach to use 30-day periods to calculate the dividend yields. However, under the basic financial principle that financial markets are efficient, *i.e.*, the current stock prices fully reflect all publicly available information, it may be appropriate to avoid using long-term historical prices. Such long-term historical prices may result in biased dividend yields that reflect irrelevant information. In particular, under this principle, Mr. Hevert's use of prices over the 90- and 180-trading-day periods to calculate his dividend yields may be inappropriate. Mr. Hevert's 90- and 180-trading-day average dividend yields are seven basis points and twelve basis points higher, respectively, than his 30- trading-day average dividend yield.

Q. Did Mr. Hevert use an additional non-constant growth rate DCF analysis?

A. Yes. Mr. Hevert, on pages 24-25 of his Direct Testimony, used a Two-Growth DCF model. Similar to his constant growth DCF analysis, Mr. Hevert calculated dividend yields using 30-, 90-, and 180-trading-day closing stock price averages, and estimated required ROE assuming a low, average, and high growth rate with each dividend yield, for a total of nine multi-stage DCF estimates.

Q. Please describe the growth rates that Mr. Hevert used in his Two Growth DCF analysis.

A. For the first period, Mr. Hevert used the same three growth rates that he used in his constant growth analysis for the first five years.

For the second period, Mr. Hevert used an averaging approach that is similar to that used in the Department's Two-Growth model. He calculated the average growth rate for the OTP Proxy Group, as well as the standard deviation of the growth estimates. He then added and subtracted one standard deviation to the average growth rate to develop the upper and lower bounds for long-term sustainable growth rates.

Q. Do you agree with Mr. Hevert's Two-Growth DCF analysis?

A. Yes.

Q. Do you have any further observations of Mr. Hevert's Two-Growth DCF analysis?

A. Yes, I do. As noted above, Mr. Hevert performed Two-Growth DCF analyses using the 30-, 90-, and 180-trading-day averages for closing stock prices. As I discussed earlier in this testimony, the only reasonable estimate for stock prices is the 30-day average closing price.

C. MR. HEVERT'S CAPM ANALYSIS

Q. Please describe Mr. Hevert's CAPM analysis.

A. As noted above, the application of the CAPM requires the following parameters; a risk-free rate, the market risk premium, and beta.[15] Mr. Hevert, on pages 25 through 28 of his Direct Testimony, developed two estimates for each of these three

---

[15] As I explained previously, the basic premise of CAPM is that any company-specific risk can be diversified away by investors and, thus, the only risk that matters is the systematic risk of the stock, which is measured by beta. In its simplest form, CAPM assumes the following:

$k = r + beta\ (k_m - r)$

In the above formula, k is the required rate of return on the stock in question, r is the rate of return on a riskless asset, and k_m is the required rate of return on the market portfolio.

parameters, and ultimately developed eight estimates of OTP's required ROE using the CAPM.

Q. Please discuss the risk-free yields used by Mr. Hevert.

A. Mr. Hevert used the current 30-day average yields on 30-year Treasury bonds and a projected yield on 30-year Treasury bonds. These rates were 3.01 percent and 3.38 percent, respectively.

Q. Do you agree with Mr. Hevert's choice of risk-free rates?

A. Not completely. While the yield on 30-year Treasury bonds may be a reasonable proxy for the risk-free rate, as I discussed earlier in my testimony the 30-year Treasury bond includes an interest rate risk premium and, therefore, may bias the CAPM estimated ROE upward.

Q. Please discuss Mr. Hevert's choice of the market risk premium.

A. Mr. Hevert derived two estimates of the required market return on the S&P 500, one using data from Bloomberg, and one using data from Value Line. Using these data, Mr. Hevert performed a constant growth rate DCF analysis for each of the 500 companies in the S&P 500 and calculated the average DCF result for the entire group weighted by market capitalization. From these two estimates of required market return, Mr. Hevert subtracted the 30-day average yields on 30-year Treasury bonds to derive estimates of the market risk premium. Mr. Hevert's Bloomberg and Value Line analyses yielded market risk premium estimates of 10.51 percent and 9.80 percent respectively.

Q. Do you agree with Mr. Hevert's method of estimating the market risk premium?

A. While I use a different estimate, I have no objections to Mr. Hevert's method of estimating the required market return. I do, however, disagree with Mr. Hevert's use of 30-year Treasury yields to derive the market risk premium because, as explained above, investing in a 30-year Treasury bond would unreasonably subject the investor to interest rate risk.

Q. Please discuss Mr. Hevert's choice of beta for OTP.

A. Mr. Hevert's estimate of the beta for OTP is the average of the betas for the members of his proxy group. Mr. Hevert derived two estimates of beta for OTP, one using betas from Bloomberg, and one using betas from Value Line. His Bloomberg and Value Line beta estimates are 0.619 and 0.78, respectively.

Q. What were the results of Mr. Hevert's CAPM analyses?

A. Mr. Hevert's CAPM results range from 9.08 percent to 11.62 percent using the then-current 30 day average interest rate for the 30 year Treasury bond.

Q. As a point of reference, would the use of 30-year Treasury yields, rather and current 20-year yields, have a significant impact on your CAPM and ECAPM estimates?

A. To answer this question, I recalculated my CAPM results using 30-year Treasury yields, while retaining my estimates of beta and the required market return and then compared them to my results using 20-year Treasury yields. DOC Ex. ___ at JPK-12 (Kundert Direct). The use of 30-year Treasury yields increases my CAPM estimates by 8 to 11 basis points. Table 14 summarizes this information.

Table 14 Comparison of DOC CAPM and ECAPM Using 20 and 30 Year Treasury Yields			
Component	30 Year Treasury Yields	20 Year Treasury Yields	Difference
CAPM	7.89%	7.78%	-0.11%
ECAPM	8.36%	8.28%	-0.08%
Source:			
	DOC Exhibit No. ___ at JPK-4, Schedule 1		
	DOC Exhibit No. ___ at JPK-12, Schedule 1		

Based on this small difference, it is clear that the difference between Mr. Hevert's CAPM estimates and my own are largely the result of differences in our estimates of the required return on the market portfolio, and specifically the differences in the earnings growth rates we use for the S&P 500. My estimate of 7.64 percent comes from Thomson, while Mr. Hevert's estimates of 10.51 and 9.80 percent are calculated using estimates from Bloomberg and Value Line respectively. All three are respected sources of financial data, and thus the difference between them is likely attributable to a diversity of opinion among analysts, and thus all could be considered reasonable. The significant difference that our growth rate estimates cause in our CAPM results highlights the difficulties in applying the CAPM model, which again lead me to use it only as a check on my DCF results, rather than a method equal to the DCF.

D. MR. HEVERT'S RISK PREMIUM ANALYSIS

Q. Please discuss Mr. Hevert's bond yield plus risk premium analysis.

A. As described on pages 28 and 29 of Mr. Hevert's testimony, the approach of using the bond yield plus risk premium treats the cost of equity as a sum of an equity risk premium and a bond yield. Mr. Hevert chose 30-year Treasuries as the representative bond for his analysis, and estimated the market risk premium by calculating the difference between ROEs authorized in electric utility rate proceedings between January 1980 and December 15, 2015, and then subtracted the then-current average 30-year Treasury yields. The average risk premium over this period is 4.49 percent.[16]

Q. Did Hr. Hevert use this average risk premium of 4.49 percent as his estimate of the risk premium?

A. No. After calculating actual risk premiums, Mr. Hevert used a linear regression to estimate the risk premium as a function of the natural log of the prevailing 30-year Treasury yields using the following equation:

$$\text{Risk Premium} = \alpha + \beta * \ln(\text{Treasury yield})$$

Mr. Hevert estimated the constant, α, to be negative 0.0274 and the coefficient, β, to be negative 0.0279. Using the same current yield on 30-year Treasury yields as his CAPM analysis (3.01 percent), a near-term forecast of the 30-year Treasury yields (3.38 percent) and a long-term forecasted yield on 30-year Treasuries (4.65 percent), Mr. Hevert estimated the risk premium to be between 5.83 percent and 7.04 percent. These estimates result in a range of estimated

[16] See OTP Ex. ___ at RBH-1, Schedule 7 (Hevert Direct).

required returns on equity between 10.05 percent and 10.48 percent. OTP Ex. ___ at 28-31 (Hevert Direct).

Q. Do you agree that Mr. Hevert has shown it is reasonable to use his bond yield plus risk premium analysis?

A. No. Mr. Hevert's regression analysis assumes that both coefficients, $\alpha = -0.0274$ and $\beta = -0.0279$ are stable over time and do not depend on investors adjusting their expectations depending on different Federal monetary and fiscal policies. To the degree that investors adjust their behavior to adapt to changing Federal policies, neither of the coefficients are stable and therefore cannot be used to estimate the expected risk premium.

Q. Did Mr. Hevert consider other factors in developing his recommended required return on equity?

A. Yes. Mr. Hevert considered flotation costs. In addition, on pages 50 and 51 of his Direct Testimony, Mr. Hevert stated that his recommendation also took into consideration the capital environment in which OTP operates, its substantial capital investment plans, and the Company's small size. In addition, Mr. Hevert considered OTP's high level of customer satisfaction and its under-budget completion of its AQCS capital project OTP's concentration of transportation revenues, and its substantial capital investment plans. OTP Ex. ___ at 32-41 (Hevert Direct).

E. FLOTATION COSTS

Q. Do you have any concerns related to Mr. Hevert's adjustment for flotation costs?

A. Yes. As noted above, Mr. Hevert's estimate of flotation costs is included in OTP Ex. ___ at RBH-1, Schedule 2, page 3 of 3 (Hevert Direct). His estimate is 3.944 percent. These calculations are based on the issuance costs of OTC stock. He then uses a Constant Growth DCF model consisting of the companies in OTP's Proxy Group to determine the effect of the inclusion of flotation costs on the OTP Proxy Group's average ROE. Mr. Hevert's estimate of the flotation cost adjustment is 16 basis points. I reviewed the Company's calculations and conclude that Mr. Hevert's approach for calculating flotation costs is reasonable.

As noted earlier in my Direct Testimony, the DOC Proxy Group's member companies are different to some extent from the companies included in OTP's Proxy Group.

Consistent with the concept that calculation of the flotation cost adjustment should be based on the companies included in the proxy group. I calculated a separate flotation cost adjustment using the DOC Proxy Group while using the Company's estimate of its flotation costs of 3.944 percent.[17] This resulting DOC flotation cost adjustment is equal to 13 basis points.

[17] A modified version of OTP Ex. ___ at RBH-2, Schedule 1 (Hevert Direct) as described is included as DOC Ex. ___ at JPK-3, Schedule 7 (Kundert Direct).

F. MR. HEVERT'S RISK ADJUSTMENTS

Q. Please summarize Mr. Hevert's risk adjustments.

A. Mr. Hevert's risk analysis identified several risk indicators in his direct testimony. These indicators included:

- Capital expenditures;
- Small size; and
- Customer concentration.

Q. Do you have any observations about Mr. Hevert's business risk-related adjustments?

A. Yes. I do not support this type of *ad hoc* adjustment to any regulated utility's cost of equity.

Q. Please continue.

A. As discussed above regarding the screening criteria, I conclude that these types of business risks are considered by the different credit rating agencies and incorporated into a company's credit rating (OTP in this instance). Given that Mr. Hevert used "investment grade debt" credit rating (BBB- and above) as a screening criterion for the OTP Proxy Group, and I used a corporate debt rating of BBB- to BBB+ as a screening criterion for the DOC Proxy Group, my position is that the business risks Mr. Hevert alludes to have already been incorporated into the analyses developed for OTP's cost of equity. Selecting a cost of equity in the upper half of Mr. Hevert's proposed range of estimates for OTP's cost of equity upward to account for these risks is the equivalent of accounting for these risks twice.

Q. Please discuss the specific risk indicators used by Mr. Hevert.

A. On pages 32-36 of his Direct Testimony, he discussed the Company's high level of capital expenditures as a source of risk. He cited one S&P document at length. OTP Ex. ___ at 32-36 (Hevert Direct).

Q. What is your response to this risk indicator?

A. Returning to my earlier comments regarding the inclusion of this risk in the evaluation of a utility's overall risk profile, I note that S&P has stated in its publication: "Key Credit Factors For The Regulated Utilities Industry" --

> Operating Efficiency – . . . We consider the key factors for this component of competitive position to be: Compliance with the terms of its operating license . . .; Cost management; and ***Capital spending; scale, scope and management***.
>
> [Emphasis added].[18]

One of OTP's witnesses in this proceeding appears to support this position as well. Mr. Kevin G. Moug states on page 13 of his Direct Testimony – "Capital expenditures levels and the regulatory environment are both significant to credit rating agencies' evaluation of a utility's credit ratings."[19]

Q. Please summarize the large capital expenditure issue.

[18] S&P, Ratings Services July 24, 2015, Criteria/Corporates/Utilities: Key Credit Factors For the Regulated Utilities Industry, paragraph 38, page 6 of 14.
[19] OTP Ex. ___ at 13 (Moug Direct).

A. Based on my analysis above, I conclude that no capital expenditure-related risk premium on the return on equity for OTP has been shown to be reasonable.

Q. Please discuss the second risk indicator mentioned by Mr. Hevert.

A. Mr. Hevert, on pages 36-37 of his Direct Testimony, testified that investors in smaller companies face higher liquidity risks and fundamental business risks, which result in investors demanding higher required rates of return from their investments in smaller companies. Mr. Hevert testified that because OTP is smaller than companies included in his proxy group, its investors face a higher level of risk than investors in his proxy companies, and therefore the results of his DCF, CAPM, and bond yield plus risk premium analyses understate OTP's cost of equity. OTP Ex. ___ at 37-38 (Hevert Direct).

Mr. Hevert estimated that OTP's small size relative to the proxy group would generally be associated with an increase in its cost of equity of 159 basis points relative to his proxy group. While Mr. Hevert does not make a specific direct adjustment to the results of his DCF, CAPM, or bond yield premium analyses, he did consider his assessment of OTP's small size premium in developing his final recommendations.

Q. Do you agree with Mr. Hevert's small-size argument?

A. I agree that, in general, that there exists a "risk premium" for smaller size companies. However, this principle is true under the premise of "all other things the same," which means that for two identical companies in all aspects, other than size, the company that is significantly smaller would have a higher required rate of return. However, as I noted previously, OTP's size is only one aspect of the Company's overall financial and business risk that is already reflected in the Company's credit ratings; thus this risk is subsumed in OTP's credit rating.

Company witness Kevin Moug appears to provide support for my position as well as stating in his Direct Testimony at page 15:

> Moody's has recently noted OTP's size and service area as factors that affect its credit rating:

Q. Please summarize the issue of small-size risk premium.

A. Based on my analysis above, I conclude that no small-size risk premium on the return on equity for OTP has been shown to be reasonable.

Q. Does Mr. Hevert identify a third risk indicator beyond OTP's level of capital expenditures and small size?

A. Yes. Mr. Hevert also included a discussion in his testimony at pages 38 and 39 regarding customer concentration. Mr. Hevert noted in his testimony that approximately 68 percent of OTP's total revenues and 70 percent of "its total sales volumes are attributable to sales to commercial and industrial customers".[20] He noted that relative to the OTP Proxy Group the Company had the second highest customer concentration by percent of revenues and the fourth highest commercial customer concentration by percent of volume.

Q. What is your response to this risk indicator?

[20] OTP Ex. ___ at page 38 (Hevert Direct)

A. I agree that, in general, a customer base that consists primarily of large commercial and industrial customers may present more revenue-related risk for an electric utility than a customer base that consists primarily of residential and small commercial customers. Similar to Mr. Hevert's earlier "small size" argument, this principle is true under the premise of "all other things the same," which means that for two identical companies in all aspects, other the make-up of their respective customer bases, the company that bills more revenue to large commercial and industrial customers would have a higher required rate of return. However, as I noted previously, OTP's customer concentration is only one aspect of the Company's overall financial and business risk. Once again, I note that this risk is subsumed in OTP's credit rating.

Q. Can you provide some additional detail on this topic?

A. Yes. From what I can ascertain, S&P would evaluate this particular risk under the section titled "Scale, scope and diversity" located on page 5 of the previously mentioned publication. S&P notes:

> We [S&P] consider the key factors for this component of competitive position to be primarily operational scale and diversity of the geographic, economic and regulatory footprints. We [S&P] focus on a utility's markets, service territories, and diversity and the extent to which these attributes can contribute to cash flow stability while dampening the effect of economic and market threats. . . . A small customer base, especially if burdened by customer and/or industry concentration combined with little economic diversity an average to below-average economic prospects.[21]

Q. Please summarize the issue of customer concentration.

[21] S&P, Ratings Services July 24, 2015, Criteria/Corporates/Utilities: Key Credit Factors For the Regulated Utilities Industry, paragraph 31 - 33, page 5 of 14.

A. Based on my analysis above, I conclude that any risk associated with customer concentration has been subsumed in the credit rating screening criterion used to develop the DOC Proxy Group and that no customer concentration-related risk premium on the return on equity for OTP has been shown to be warranted.

G. MR. HEVERT'S PROPOSAL FOR AN INCENTIVE PREMIUM FOR THE COMPANY'S RETURN ON EQUITY

Q. Please summarize Mr. Hevert's proposed incentive adjustment for OTP's cost of equity.

A. On pages 39-41 of his Direct Testimony, he discussed the Company's successes in managing its capital budget relative to the Big Stone Air Quality Control System project and a smaller Hoot Lake project. Mr. Hevert also mentions the high levels of customer satisfaction that OTP has identified.

Q. Please continue.

A. Mr. Hevert then posits that it would be appropriate for the Commission to provide a premium in excess of the authorized rate of return as a reward of sorts for OTP's efforts in terms of its managing its capital budgeting and high levels of customer satisfaction.

Q. Did Mr. Hevert identify an explicit adjustment to his ROE recommendation to recognize this proposed incentive premium?

A. No, he didn't.

Q. What is your response to Mr. Hevert's proposed incentive premium on OTP authorized rate of return?

A. I don't believe the addition of an incentive premium to OTP's authorized rate of return is reasonable in this proceeding.

Q. Why not?

A. When evaluating a proposal of this nature, I often consider the request in light of a symmetrical economic hypothetical. In this instance, it would be a hypothetical in which OTP would have had significant cost overruns for the two capital projects and was simultaneously experiencing low customer satisfaction numbers. Given that hypothetical, it is unlikely that OTP would be requesting that the Commission subtract an unspecified amount from its authorized rate of return in light of its poor performance. To my knowledge, no electric utility in the United States has ever proposed such a plan. Consequently, I don't believe the proposal is reasonable.

Q. Are there any other items that support your position?

A. An incentive for the cost of equity is usually associated with some form of performance-based regulation. OTP is currently under cost of service regulation, not performance-based regulation. To my knowledge, cost-of-service regulation does not consider an explicit premium to a utility's authorized rate of return as a "cost" in the traditional sense. As a result, the inclusion of such a cost would be inconsistent with the tenets of cost-of-service regulation. Moreover, OTP already received a significant benefit due to rider recovery of the costs associated with the Big Stone Air Quality Control project before the facility was even in place, providing service to ratepayers.

In addition, OTP has the burden of proof to demonstrate that its costs are reasonable if the Company wants those costs to be reflected in rates under cost-of-service regulation. OTP would need to provide a much higher level of review and discussion for the Department to conclude that the Company has met this burden of proof for this proposal.

H. CAPITAL MARKET ENVIRONMENT

Q. Please describe generally Mr. Hevert's analysis of current economic conditions and their impact on OTP's cost of equity.

A. On pages 41-45 of his Direct Testimony, Mr. Hevert described the Federal Reserve's market interventions over the past several years, the impact these interventions have had on interest rates, and uncertainty surrounding the Federal Reserve's future policy decisions. On page 44 of his Direct Testimony, Mr. Hevert posited that expectations for increasing interest rates into 2018 and beyond, and the Federal Reserve's efforts to "normalize" it monetary policy, support his 10.40 percent recommended cost of equity.

Q. Did Mr. Hevert make a specific adjustment to the results of his ROE analyses to account for this uncertainty?

A. No.

Q. Do you agree that the results of financial models used to estimate the cost of equity need to be adjusted, directly or indirectly, to reflect uncertainty regarding the future actions of the Federal Reserve?

A. No. Investor expectations regarding future interest rate changes or changes to other general economic factors are already fully reflected in asset prices.

Q. Please explain.

A. Reasonable investors would not likely hold an investment if they believed that it is likely to perform poorly. Thus, if investors expected the price of a stock to fall, they would sell the stock, bidding the price of the stock down until it reaches a point at which the expected return meets investors' required return. More specifically, if investors expect interest rates to rise in the future and also expect that rise to negatively impact the price of their stock holdings, they will bid the price of their stock holdings down until its expected return matches its required return.

In this way, the uncertainty regarding the future actions of the Federal Reserve is already fully reflected in stock prices. And because the financial models used to estimate the cost of equity rely on current stock prices, the results of those models also reflect current investor expectations. Therefore, any additional adjustments, either direct or indirect, intended to reflect investor expectations would not only be unnecessary, they would be unreasonable.

I. CAPITAL STRUCTURE

Q. Please describe Mr. Hevert's analysis of OTP's proposed capital structure.

A. On pages 45 through 49 of his Direct Testimony Mr. Hevert discusses the importance of capital structure and developed an analysis that compared OTP's proposed capital structure to the average capital structure of the companies contained in the OTP

Proxy Group over a two year period (8 quarters). He concluded that OTP's proposed test year capital structure is appropriate.

Q. Do you have any comments regarding Mr. Hevert's analysis?

A. Yes. Mr. Hevert's analysis uses the OTP Proxy Group. As noted earlier in my testimony, inappropriate screening criteria were used to develop the OTP Proxy Group. The use of the OTP Proxy Group influences the results of his capital structure analysis. For that reason, I recommend that the Commission discount his analysis.

Q. Your disagreements with Mr. Hevert's DCF, CAPM, and risk premium analyses notwithstanding, do you agree that his results, presented in Tables 7a and 7b of his Direct Testimony, support his conclusion regarding the reasonable range of 10.00 to 10.60 percent and his recommended ROE of 10.40 percent?

A. No, I cannot confirm his figures since Mr. Hevert did not quantify the impacts of -- 1) the small-size premium, 2) the customer concentration premium, 3) the level of the premium associated with the Company's capital expenditures, 4) the level of his proposed ROE incentive or 5) the current capital market environment -- on his recommended ROE. I note, however, that the lower bound of his reasonableness range for OTP's cost of equity, 10.00 percent, is 10 basis points higher than his mean constant growth rate DCF results, and 23 basis points higher than his mean 30-day multi-stage DCF results.

Q. What do these comparisons lead you to conclude about Mr. Hevert's figures?

A. Based on these significant differences, it appears that Mr. Hevert's final recommendation either includes significant adjustments for the small-size premium, revenue concentration, capital expenditures, a ROE incentive and current capital market conditions, or is weighted more heavily on his CAPM and risk premium analyses.

If the former explains Mr. Hevert's conclusions then, as I have explained earlier in my testimony, no adjustments related to: 1) the small-size premium, 2) the customer concentration premium, 3) the capital expenditure premium, 4) an ROE incentive, or 5) current capital market conditions were shown to be appropriate. Thus his final recommended ROE is unreasonably high.

If the latter formed the basis for his conclusions, then his emphasis on his CAPM and risk premium results were not shown to reasonably support his conclusions. As I noted above, the Commission historically has placed its heaviest reliance on the DCF methodology, and thus Mr. Hevert's recommended ROE of 10.40 percent is unreasonable for OTP.

Q. Please summarize your critique of Mr. Hevert's testimony.

A. While I agree with many aspects of Mr. Hevert's testimony, I disagree with some significant aspects of his analyses.

With respect to his constant growth rate and multi-stage DCF analyses, I disagree with Mr. Hevert's use of dividend yields based on 90- and 180-day average stock prices, and his selection of the OTP Proxy Group.

With respect to his CAPM analysis, Mr. Hevert used an estimate of the risk-free rate that may not be appropriate.

Mr. Hevert's risk premium analysis may be inappropriate because it assumes that investors do not change their expectations based on changed Federal monetary and fiscal policies.

Lastly, given the results of his DCF, CAPM, and Risk Premium analyses, I disagree with Mr. Hevert's claimed reasonable range for OTP's cost of equity, as well as his recommended ROE, since both the range and recommended ROE appear to reflect either significant adjustments related to the small-size premium, revenue concentration, capital expenditures, some sort of ROE incentive and the current capital market environment, or to be based more on his CAPM and risk premium analyses than his DCF analyses.

J. RESPONSE TO COMPANY-WITNESS KEVIN G. MOUG

Q. Please summarize Mr. Moug's conclusions regarding OTP's capital structure.

A. Mr. Moug provided the analyses that support the Company's proposed capital structure, although he relies on Mr. Hevert's analysis to support his proposed equity ratio of 52.50 percent.

Q. Do you have any comments on OTP's proposed capital structure given the information Mr. Moug provided in his Direct Testimony?

A. I reviewed the exhibits included in Mr. Moug's testimony. The calculations included to determine the interest rates on the Company's short-term and long-term debt appear to be correct.

Q. Do you have any comments on the balance of Mr. Moug's Direct Testimony?

A. No.

VII. CONCLUSION

Q. What is your current recommendation for OTP's overall cost of capital?

A. CORRECTED Table 15, which is identical to CORRECTED Table 9 above, summarizes my recommended capital structure as well as my recommended costs of long-term debt, short-term debt, and the cost of equity.

CORRECTED -Table 15 DOC Proposed 2016 Test Year Capital Structure			
Component	**Proposed Capital Structure**	**Proposed Cost**	**Weighted Cost of Capital**
	[1]	[2]	[3] = [1] x [2
Long-term Debt	44.90%	5.62%	2.52%
Short-term Debt	2.60%	3.28%	0.09%
Common Equity	52.50%	8.87%	4.66%
Total	100.00%		7.27%

As shown, I recommend an overall cost of equity of 7.27 percent.

Q. Do you plan to update your recommendations in your Surrebuttal Testimony?

A. Yes. I will update my recommended cost of equity and overall cost of capital, based on the most recent available market data.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

John P. Kundert
Professional Background and Education

EMPLOYMENT

Minnesota Department of Commerce (2014 – Present)
Public Utilities Financial Analyst 3

TransCanada (2013)
Manager of Rates and Tariffs

Xcel Energy (2000 – 2013)
Manager of Pricing

Connexus Energy (1997 – 2000)
Cost Analyst

Minnesota Department of Public Service (now Commerce) (1990 – 1997)
Public Utilities Rates Analyst 4

Hargrove and Associates (1988 – 1989)
Marketing Director

EDUCATION

UNIVERSITY OF MINNESOTA, Minneapolis, MN
Department of Agricultural and Applied Economics
Masters of Science, 1988

UNIVERSITY OF IOWA, Iowa City, IA
Bachelor of Science, 1979
Major: General Science

PREVIOUS TESTIMONY

Company	Docket No.	Jurisdiction	Subject
MN Dept. of Commerce	G011/GR-15-736	Minnesota	Rate of Return
Xcel Energy	11AL-151G	Colorado	Rate Design
Xcel Energy	10-963G	Colorado	Gas Storage Inventory Cost
Xcel Energy	09AL-299E	Colorado	ECA
Xcel Energy	08S-146G	Colorado	Class Cost of Service Study
Xcel Energy	05S-264G	Colorado	Class Cost of Service Study
MN Dept. of Commerce	E015/GR-94-001	Minnesota	Rate Design
MN Dept. of Commerce	E999/CI-93-583	Minnesota	Environmental Externalities
MN Dept. of Commerce	E002/GR-92-1185	Minnesota	Class Cost of Service Study

DOC Proxy Group Screening Process
Electric Proxy Group - Standard Industrial Classification Code 4911

Line No.	Company	Ticker	Incorporated in U.S.A.	S&P Debt Rating	S&P Debt Rating Between BBB- and BBB+	Preliminary US & Debt Rating Screen	Absence of Merger or Acquisition Activity	Covered by More than One Equity Analyst	Consistent Dividends	Covered by Value Line and either Zacks or Thomson	Retail Electric Service	60% Operating Income from U.S. Regulated Retail Ops.	**Initial Electric or Combination Proxy Group Member**	Constant Growth DCF > 7.00%	**Final DOC Proxy Group Member**
1.	AMERICAN ELECTRIC POWER	AEP	y	BBB	y	1	y	y	y	y	y	y	y	y	y
2.	AVANGRID	AGR	y	not rated	n	0									
3.	BLACK HILLS CORP	BKH	y	BBB	y	1	n								
4.	BROOKFIELD INFRS PTRS LP	BIP	n	BBB+	y	0									
5.	CENTRAIS ELECTRICAS - ADR	EBR	n	BB	n	0									
6.	CIA ENERGETICA MINA GERAIS - ADR	CIG	n	not rated	n	0									
7.	CIA PARANAENSE ENERGIA - ADR	ELP	n	not rated	n	0									
8.	CLECO CORP	CNL	y	BBB-	y	1	n								
9.	CPFL ENERGY INC. - ADR	CPL	n	not rated	n	0									
10.	DOMINION RESOURCES INC.	D	y	BBB+	y	1	n								
11.	EDISON INTERNATIONAL	EIX	y	BBB+	y	1	y	y	y	y	y	y	y	n	
12.	EL PASO ELECTRIC CO	EE	y	BBB	y	1	y	y	y	y	y	y	y	y	y
13.	EMPIRE DISTRICT ELECTRIC CO	EDE	y	BBB	y	1	n								
14.	EMPRESA DISTRIB Y COMERC - ADR	EDN	n	not rated	n	0									
15.	EMPRESA NAC ELEC CHILE - ADR	EOCC	n	BBB+	y	0									
16.	ENDESA AMERICAS SA - ADR - SPN	EOCA	n	not rated	n	0									
17.	ENERSIS AMERICAS SA - ADR	ENIA	n	BBB	y	0									
18.	ENERSIS CHILE SA - ADR - SPN	ENIC	n	not rated	n	0									
19.	ENTERGY CORP	ETR	y	BBB	y	1	y	y	y	y	y	y	y	n	
20.	EXELON CORP	EXC	y	BBB	y	1	n								
21.	FIRSTENERGY CORP	FE	y	BBB-	y	1	y	y	y	y	y	y	y	n	
22.	GREAT PLAINS ENERGY	GXP	y	BBB+	y	1	n								
23.	HAWAIIAN ELECTRIC INDS	HE	y	BBB-	y	1	n								
24.	HUANENG POWER INTL INC - ADR	HNP	n	not rated	n	0									
25.	IDACORP INC	IDA	y	BBB	y	1	y	y	y	y	y	y	y	n	
26.	ITC HOLDINGS CORP	ITC	y	A-	y	1	n								
27.	KOREA ELECTRIC POWER CO - ADR	KEP	n	AA-	n	0									
28.	NATIONAL GRID PLC - ADR	NGG	n	A-	y	0									
29.	NEXTERA ENERGY INC	NEE	y	A-	y	1	n								
30.	NEXTERA ENERGY PARTNERS LP	NEP	y	not rated	n	0									
31.	NRG ENERGY INC	NRG	y	BB-	n	0									
32.	NRG YIELD INC	NYLD.A	y	BB+	n	0									
33.	ORMAT TECHNOLOGIES	ORA	y	not rated	n	0									
34.	PAMPA ENERGIA SA - ADR	PAM	n	not rated	n	0									
35.	PEPCO HOLDINGS INC	POM	y	BBB+	y	1	n								
36.	PINNACLE WEST CAPITAL CORP	PNW	y	A-	n	0									
37.	PNM RESOURCES INC.	PNM	y	BBB+	y	1	y	y	y	y	y	y	y	y	y
38.	PORTLAND GENERAL ELECTRIC CO	POR	y	BBB	y	1	y	y	y	y	y	y	y	y	y
39.	PPL CORP	PPL	y	A-	y	1	y	y	y	y	y	n			
40.	SOUTHERN CO.	SO	y	A-	y	1	n								
41.	TALEN ENERGY CORP	TLN	y	not rated	n	0									
42.	TERRAFORM POWER INC	TERP	y	B-	n	0									
43.	TRANSALTA CORP	TAC	n	BBB-	y	0									

Notes:

1) A "0" in the Preliminary U.S. or Debt column G or a no or "n" in bold in any of the subsequent columns identifies the criterion that eliminated the particular company.

2) Blank cells indicate that the screen was not performed as the company had failed a prior test.

DOC Proxy Group Screening Process
Comparable Proxy Group - Standard Industrial Classification Code 4931

Line No.	Company	Ticker	Incorporated in U.S.A.	S&P Debt Rating	S&P Debt Rating Between BBB- and BBB+	Preliminary US & Debt Rating Screen	Absence of Merger or Acquisition Activity	Covered by More than One Equity Analyst	Consistent Dividends	Covered by Value Line and either Zacks or Thomson	Retail Electric Service	60% Operating Income from U.S. Regulated Electric Retail Ops.	Initial Electric or Combination Proxy Group Member	Constant Growth DCF > 7.00%	Final DOC Proxy Group Member
1.	ALLETE INC	ALE	y	BBB+	y	1	y	y	y	y	y	y	y	y	y
2.	ALLIANT ENERGY CORP	LNT	y	A-	n	0									
3.	AMEREN CORP	AEE	y	BBB+	y	1	y	y	y	y	y	y	y	y	y
4.	AVISTA CORP	AVA	y	BBB	y	1	y	y	y	y	y	y	y	y	y
5.	CENTERPOINTE ENERGY INC	CNP	y	A-	n	0									
6.	CMS ENERGY CORP	CMS	y	BBB+	y	1	y	y	y	y	y	y	y	y	y
7.	CONSOLIDATED EDISON INC	ED	y	A-	n	0									
8.	DTE ENERGY CO	DTE	y	BBB+	y	1	y	y	y	y	y	y	y	y	y
9.	DUKE ENERGY CORP	DUK	y	A-	n	0									
10.	EVERSOURCE ENERGY	ES	y	A	n	0									
11.	GENIE ENERGY LTD	GNE	y	not rated	n	0									
12.	MGE ENERGY INC	MGEE	y	not rated	n	0									
13.	NORTHWESTERN CORP	NWE	y	BBB	y	1	y	y	y	y	y	y	y	y	y
14.	OGE ENERGY CORP	OGE	y	A-	n	0									
15.	PG&E CORP	PCG	y	BBB	y	1	y	y	y	y	y	y	y	y	y
16.	PUBLIC SERVICE ENTRP GRP INC	PEG	y	BBB+	y	1	y	y	y	y	y	n			
17.	SCANA CORP	SCG	y	BBB+	y	1	y	y	y	y	y	y	y	y	y
18.	SEMPRA ENERGY	SRE	y	BBB+	y	1	y	y	y	y	y	n			
19.	TECO ENERGY INC	TE	y	BBB+	y	1	n								
20.	UNITIL CORP	UTL	y	BBB+	y	1	y	y	y	n					
21.	WEC ENERGY GROUP INC	WEC	y	A-	n	0									
22.	WESTAR ENERGY INC	WR	y	BBB+	y	1	n								
23.	XCEL ENERGY	XEL	y	A-	n	0									

Notes:

1) A "0" in the Preliminary U.S. or Debt column G or a no or "n" in bold in any of the subsequent columns identifies the criterion that eliminated the particular company.

2) Blank cells indicate that the screen was not performed as the company had failed a prior test.

Constant Growth DCF Analysis - 4911 Proxy Group

Company	Ticker	SIC	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
American Electric Power	AEP	4911	68.11	2.24	3.29%	3.77%	4.32%	4.69%	3.35%	3.36%	3.37%	7.12%	7.68%	8.06%
Edison International	EIX	4911	75.34	1.92	2.55%	2.55%	3.80%	5.34%	2.58%	2.60%	2.62%	5.13%	**6.39%**	7.96%
El Paso Electric Company	EE	4911	46.39	1.24	2.67%	2.50%	4.60%	6.70%	2.71%	2.73%	2.76%	5.21%	7.33%	9.46%
Entergy Corp	ETR	4911	79.39	3.40	4.28%	-2.25%	-0.37%	3.00%	4.23%	4.27%	4.35%	1.98%	**3.91%**	7.35%
FirstEnergy Corp	FE	4911	34.45	1.44	4.18%	-3.24%	1.25%	9.00%	4.11%	4.21%	4.36%	0.87%	**5.46%**	13.36%
IdaCorp Inc	IDA	4911	77.51	2.04	2.63%	3.00%	3.67%	4.00%	2.67%	2.68%	2.68%	5.67%	**6.35%**	6.68%
PNM Resources Inc	PNM	4911	34.39	0.88	2.56%	7.60%	8.45%	9.00%	2.65%	2.66%	2.67%	10.25%	11.12%	11.67%
Portland General Electric Company	POR	4911	43.04	1.28	2.97%	5.50%	6.17%	6.57%	3.05%	3.06%	3.07%	8.55%	9.24%	9.64%
Mean						2.43%	3.99%	6.04%	3.17%	3.20%	3.23%	5.60%	7.18%	9.27%

Sources and Notes:
[1] DOC Ex. ___ JPK-3, Schedule 6
[2] Yahoo! Finance
[3] = [2] / [1]
[4] DOC Ex.___JPK-3, Schedule 5
[5] DOC Ex.___JPK-3, Schedule 5
[6] DOC Ex.___JPK-3, Schedule 5
[7] = [3] x (1+[4])^0.5
[8] = [3] x (1+[5])^0.5
[9] = [3] x (1+[6])^0.5
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

DOC CAPM Analysis for 4911 SIC Code

	Line No.	Formula/Note	
Risk-free Rate	[1]	DOC Ex.___JPK-4, Schedule 2	1.95%
Thomson First Call Projected S&P Earnings Growth Rate	[2]	DOC Ex.___JPK-4, Schedule 3	7.64%
Dividend Yield on S&P 500	[3]	DOC Ex.___JPK-4, Schedule 4	2.05%
Dividend Yield on S&P 500 with One Half Years' Worth of Growth	[4]	= [3] x (1+[2])^0.5	2.13%
DCF Required Market Return	[5]	= [2] + [4]	9.77%
β	[6]	DOC Ex. ___ JPK-4, Schedule 5	0.76
Market Risk Premium	[7]	= [6] x ([5] - [1])	5.94%
Required Return for OTP (Simple CAPM)	[8]	= [1] + [6] x ([5] - [1])	7.89%
Flotation Cost Adjustment	[9]	DOC Ex. ___ JPK-3, Schedule 7	0.13%
Simple CAPM with Flotation Costs	[10]	= [7] = [8]	8.02%

Constant Growth DCF Analysis - 4931 Proxy Group

Company	Ticker	SIC	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
ALLETE INC	ALE	4931	62.26	2.08	3.34%	4.00%	4.83%	5.50%	3.41%	3.42%	3.43%	7.41%	8.25%	8.93%
Alliant Energy Corp	LNT	4931	39.38	1.18	3.00%	6.00%	6.30%	6.60%	3.09%	3.09%	3.09%	9.09%	9.39%	9.69%
Ameren Corp	AEE	4931	51.80	1.70	3.28%	5.00%	5.42%	6.07%	3.36%	3.37%	3.38%	8.36%	8.79%	9.45%
Avista Corp	AVA	4931	43.03	1.37	3.18%	5.00%	5.00%	5.00%	3.26%	3.26%	3.26%	8.26%	8.26%	8.26%
Centerpointe Energy Inc	CNP	4931	23.48	1.03	4.39%	0.00%	3.70%	5.60%	4.39%	4.47%	4.51%	4.39%	8.17%	10.11%
CMS Energy Corp	CMS	4931	44.28	1.24	2.80%	6.00%	6.61%	7.24%	2.88%	2.89%	2.90%	8.88%	9.50%	10.14%
Consolidated Edison	ED	4931	78.29	2.68	3.42%	1.50%	2.05%	2.70%	3.45%	3.46%	3.47%	4.95%	5.51%	6.17%
DTE Energy Co	DTE	4931	95.92	2.92	3.04%	4.50%	5.22%	5.80%	3.11%	3.12%	3.13%	7.61%	8.34%	8.93%
American Electric Power	AEP	4911	68.11	2.24	3.29%	3.77%	4.32%	4.69%	3.35%	3.36%	3.37%	7.12%	7.68%	8.06%
El Paso Electric Company	EE	4911	46.39	1.24	2.67%	2.50%	4.60%	6.70%	2.71%	2.73%	2.76%	5.21%	7.33%	9.46%
PNM Resources Inc	PNM	4911	34.39	0.88	2.56%	7.60%	8.45%	9.00%	2.65%	2.66%	2.67%	10.25%	11.12%	11.67%
Portland General Electric Company	POR	4911	43.04	1.28	2.97%	5.50%	6.17%	6.57%	3.05%	3.06%	3.07%	8.55%	9.24%	9.64%
Xcel Energy Inc	XEL	4931	43.38	1.36	3.14%	5.23%	5.33%	5.50%	3.22%	3.22%	3.22%	8.45%	8.55%	8.72%
Mean						4.35%	5.23%	5.92%	3.23%	3.24%	3.25%	7.58%	8.47%	9.17%

Sources and Notes:
[1] DOC Ex. ___ JPK-3, Schedule 6
[2] Yahoo! Finance
[3] = [2] / [1]
[4] DOC Ex.___JPK-3, Schedule 5
[5] DOC Ex.___JPK-3, Schedule 5
[6] DOC Ex.___JPK-3, Schedule 5
[7] = [3] x (1+[4])^0.5
[8] = [3] x (1+[5])^0.5
[9] = [3] x (1+[6])^0.5
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

DOC CAPM Analysis for 4931 SIC Code

	Line No.	Formula/Note	
Risk-free Rate	[1]	DOC Ex.___JPK-4, Schedule 2	1.95%
Thomson First Call Projected S&P Earnings Growth Rate	[2]	DOC Ex.___JPK-4, Schedule 3	7.64%
Dividend Yield on S&P 500	[3]	DOC Ex.___JPK-4, Schedule 4	2.05%
Dividend Yield on S&P 500 with One Half Years' Worth of Growth	[4]	= [3] x (1+[2])^0.5	2.13%
DCF Required Market Return	[5]	= [2] + [4]	9.77%
β	[6]	DOC Ex. ___ JPK-4, Schedule 5	0.75
Market Risk Premiu,	[7]	= [6] x ([5] - [1])	5.87%
Required Return for OTP (Simple CAPM)	[8]	= [1] + [6] x ([5] - [1])	7.81%
Flotation Cost Adjustment	[9]	DOC Ex. ___ JPK-3, Schedule 7	0.13%
Simple CAPM with Flotation Costs	[10]	= [7] = [8]	7.94%

Value Line Betas
For Member of
DOC 4911 and 4931 Proxy Groups

Ticker	SIC Code 4911	SIC Code 4931
AEP	0.70	
EIX	0.70	
EE	0.75	
IDA	0.80	
PNW	0.75	
PNM	0.80	
POR	0.80	
ALE		0.80
LNT		0.80
AEE		0.75
AVA		0.75
CNP		0.85
CMS		0.75
ED		0.55
DTE		0.75
NEW		0.70
OGE		0.95
PCG		0.70
PEG		0.75
SCG		0.70
XEL		0.70
Average	0.76	0.75

Docket No. E017/GR-15-1033
REVISED DOC Ex. __ JPK-3, Schedule 1

CORRECTED - Constant Growth DCF Analysis - DOC Proxy Group

Company	Ticker	SIC	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
ALLETE, Inc.	ALE	4931	62.26	2.08	3.34%	4.00%	4.83%	5.50%	3.41%	3.42%	3.43%	7.41%	8.25%	8.93%
American Electric Power Company, Inc.	AEP	4911	68.11	2.24	3.29%	3.77%	4.32%	4.69%	3.35%	3.36%	3.37%	7.12%	7.68%	8.06%
Ameren Corporation	AEE	4931	51.80	1.70	3.28%	5.00%	5.42%	6.07%	3.36%	3.37%	3.38%	8.36%	8.79%	9.45%
Avista Corporation	AVA	4931	43.03	1.37	3.18%	5.00%	5.00%	5.00%	3.26%	3.26%	3.26%	8.26%	8.26%	8.26%
CMS Energy Corporation	CMS	4931	44.28	1.25	2.82%	6.00%	6.61%	7.24%	2.91%	2.92%	2.93%	8.91%	9.53%	10.17%
DTE Energy Company	DTE	4931	95.92	2.92	3.04%	4.50%	5.22%	5.80%	3.11%	3.12%	3.13%	7.61%	8.34%	8.93%
El Paso Electric Company	EE	4911	46.39	1.24	2.67%	2.50%	4.60%	6.70%	2.71%	2.73%	2.76%	5.21%	7.33%	9.46%
NorthWestern Corporation	NWE	4931	61.25	2.00	3.27%	5.00%	5.50%	6.50%	3.35%	3.36%	3.37%	8.35%	8.86%	9.87%
PG&E Corporation	PCG	4931	63.20	1.96	3.10%	5.07%	7.70%	12.00%	3.18%	3.22%	3.29%	8.25%	10.92%	15.29%
PNM Resources, Inc.	PNM	4911	34.39	0.88	2.56%	7.60%	8.45%	9.00%	2.66%	2.67%	2.67%	10.26%	11.12%	11.67%
Portland General Electric Co	POR	4911	43.04	1.28	2.97%	5.50%	6.17%	6.57%	3.06%	3.07%	3.07%	8.56%	9.24%	9.64%
Scana Corp	SCG	4931	72.88	2.30	3.16%	4.50%	5.06%	5.40%	3.23%	3.24%	3.24%	7.73%	8.29%	8.64%
Mean					3.06%	4.87%	5.74%	6.71%	3.13%	3.14%	3.16%	8.00%	8.89%	9.87%
Required ROE including flotation cost adjustment												8.13%	9.01%	9.99%
Flotation Costs												3.94%		

Sources and Notes:
[1] REVISED DOC Ex. ___ JPK-3, Schedule 6
[2] Yahoo! Finance
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-3, Schedule 5
[5] REVISED DOC Ex. __ JPK-3, Schedule 5
[6] REVISED DOC Ex. __ JPK-3, Schedule 5
[7] = [3] x (1 + 0.5 x [4])
[8] = [3] x (1 + 0.5 x [5])
[9] = [3] x (1 + 0.5 x [6])
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

CORRECTED - Two Growth Rate DCF Analysis - DOC Proxy Group
Mean Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Mean Projected Growth Rate	Mean Expected Dividend Yield	Second Growth Rate		Mean Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
ALE	62.26	2.08	3.34%	4.83%	3.42%	4.83%		8.25%
AEP	68.11	2.24	3.29%	4.32%	3.36%	4.52%		7.85%
AEE	51.80	1.70	3.28%	5.42%	3.37%	5.42%		8.79%
AVA	43.03	1.37	3.18%	5.00%	3.26%	5.00%		8.26%
CMS	44.28	1.25	2.82%	6.61%	2.92%	6.61%		9.53%
DTE	95.92	2.92	3.04%	5.22%	3.12%	5.22%		8.34%
EE	46.39	1.24	2.67%	4.60%	2.73%	4.60%		7.33%
NWE	61.25	2.00	3.27%	5.50%	3.36%	5.50%		8.86%
PCG	63.20	1.96	3.10%	7.70%	3.22%	6.96%		10.28%
PNM	34.39	0.88	2.56%	8.45%	2.67%	6.96%		9.80%
POR	43.04	1.28	2.97%	6.17%	3.07%	6.17%		9.24%
SCG	72.88	2.30	3.16%	5.06%	3.24%	5.06%		8.29%
Mean			3.06%	5.74%	3.14%	5.57%		8.74%
With Flotation Costs								8.87%
		Average		5.74%				
		Std. Dev.		1.22%			Flotation Costs (F)	3.94%
		Avg. less St. Dev.		4.52%				
		Avg. plus St. Dev		6.96%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ALE	2.13	1.08	1.97	2.23	1.17	1.91	2.34	1.27	1.85	2.45	1.37	1.79	2.57	1.49	1.73	2.70	78.83	53.02	62.26	0.00
AEP	2.29	1.08	2.12	2.39	1.16	2.05	2.49	1.25	1.98	2.60	1.35	1.92	2.71	1.46	1.86	2.83	84.90	58.17	68.11	0.00
AEE	1.75	1.09	1.60	1.84	1.18	1.56	1.94	1.29	1.51	2.05	1.40	1.46	2.16	1.52	1.42	2.27	67.46	44.26	51.80	0.00
AVA	1.40	1.08	1.30	1.47	1.17	1.26	1.55	1.27	1.22	1.63	1.37	1.18	1.71	1.49	1.15	1.79	54.92	36.92	43.03	0.00
CMS	1.29	1.10	1.18	1.38	1.20	1.15	1.47	1.31	1.12	1.56	1.44	1.09	1.67	1.58	1.06	1.78	60.99	38.69	44.28	0.00
DTE	3.00	1.08	2.77	3.15	1.17	2.69	3.32	1.27	2.61	3.49	1.38	2.53	3.67	1.49	2.46	3.86	123.69	82.87	95.92	0.00
EE	1.27	1.07	1.18	1.33	1.15	1.15	1.39	1.24	1.12	1.45	1.33	1.09	1.52	1.42	1.07	1.59	58.08	40.77	46.39	0.00
NWE	2.06	1.09	1.89	2.17	1.18	1.83	2.29	1.29	1.77	2.41	1.40	1.72	2.55	1.53	1.67	2.69	80.04	52.37	61.24	0.00
PCG	2.04	1.10	1.85	2.19	1.22	1.80	2.36	1.34	1.76	2.54	1.48	1.72	2.74	1.63	1.68	2.95	88.73	54.39	63.20	0.00
PNM	0.92	1.10	0.84	0.99	1.21	0.83	1.08	1.32	0.81	1.17	1.45	0.80	1.27	1.60	0.80	1.38	48.38	30.32	34.39	0.00
POR	1.32	1.09	1.21	1.40	1.19	1.17	1.49	1.30	1.14	1.58	1.42	1.11	1.68	1.56	1.08	1.78	58.06	37.33	43.04	0.00
SCG	2.36	1.08	2.18	2.48	1.17	2.11	2.60	1.27	2.05	2.73	1.38	1.99	2.87	1.49	1.93	3.02	93.26	62.62	72.88	0.00

Sources and Notes:
[1] REVISED DOC Ex. ___ JPK-3, Schedule 6
[2] Yahoo! Finance
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-3, Schedule 5
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (4.52%), then equal to 4.52%',
if [4] is greater than Group Avg. plu St. Dev. (6.96%), then equal to 6.96%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:
[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

UPDATED - Two Growth Rate DCF Analysis - DOC Final Combination Proxy Group
Low Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Low Expected Dividend Yield	Second Growth Rate	Low Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
ALE	62.26	2.08	3.34%	4.00%	3.41%	4.00%	7.41%
AEP	68.11	2.24	3.29%	3.77%	3.35%	3.77%	7.12%
AEE	51.80	1.70	3.28%	5.00%	3.36%	5.00%	8.36%
AVA	43.03	1.37	3.18%	5.00%	3.26%	5.00%	8.26%
CMS	44.28	1.25	2.82%	6.00%	2.91%	6.00%	8.91%
DTE	95.92	2.92	3.04%	4.50%	3.11%	4.50%	7.61%
EE	46.39	1.24	2.67%	2.50%	2.71%	3.68%	6.24%
NWE	61.25	2.00	3.27%	5.00%	3.35%	5.00%	8.35%
PCG	63.20	1.96	3.10%	5.07%	3.18%	5.07%	8.25%
PNM	34.39	0.88	2.56%	7.60%	2.66%	6.06%	8.90%
POR	43.04	1.28	2.97%	5.50%	3.06%	5.50%	8.56%
SCG	72.88	2.30	3.16%	4.50%	3.23%	4.50%	7.73%
Mean			3.06%	4.87%	3.13%	4.84%	7.98%
With Flotation Costs							8.10%
		Average		4.87%			
		Std. Dev.		1.19%		Flotation Costs (F)	3.94%
		Avg. less St. Dev.		3.68%			
		Avg. plus St. Dev		6.06%			

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ALE	2.12	1.07	1.98	2.21	1.15	1.91	2.29	1.24	1.85	2.39	1.33	1.79	2.48	1.43	1.74	2.58	75.75	52.99	62.26	0.00
AEP	2.28	1.07	2.13	2.37	1.15	2.06	2.46	1.23	2.00	2.55	1.32	1.94	2.65	1.41	1.88	2.75	81.95	58.10	68.11	0.00
AEE	1.74	1.08	1.61	1.83	1.17	1.56	1.92	1.27	1.51	2.02	1.38	1.46	2.12	1.49	1.42	2.22	66.11	44.25	51.80	0.00
AVA	1.40	1.08	1.30	1.47	1.17	1.26	1.55	1.27	1.22	1.63	1.37	1.18	1.71	1.49	1.15	1.79	54.92	36.92	43.03	0.00
CMS	1.29	1.09	1.18	1.36	1.19	1.15	1.45	1.29	1.12	1.53	1.41	1.09	1.63	1.53	1.06	1.72	59.26	38.68	44.28	0.00
DTE	2.99	1.08	2.77	3.12	1.16	2.69	3.26	1.25	2.62	3.41	1.34	2.54	3.56	1.44	2.47	3.72	119.53	82.83	95.92	0.00
EE	1.26	1.06	1.18	1.29	1.13	1.14	1.32	1.20	1.10	1.35	1.27	1.06	1.39	1.35	1.02	1.42	55.34	40.88	46.39	0.00
NWE	2.05	1.08	1.89	2.15	1.17	1.83	2.26	1.27	1.78	2.37	1.38	1.72	2.49	1.49	1.67	2.62	78.17	52.35	61.25	0.00
PCG	2.01	1.08	1.86	2.11	1.17	1.80	2.22	1.27	1.75	2.33	1.37	1.70	2.45	1.49	1.65	2.57	80.93	54.45	63.20	0.00
PNM	0.91	1.09	0.84	0.98	1.19	0.83	1.06	1.29	0.82	1.14	1.41	0.81	1.22	1.53	0.80	1.32	46.40	30.30	34.39	0.00
POR	1.32	1.09	1.21	1.39	1.18	1.18	1.46	1.28	1.14	1.54	1.39	1.11	1.63	1.51	1.08	1.72	56.25	37.31	43.04	0.00
SCG	2.35	1.08	2.18	2.46	1.16	2.12	2.57	1.25	2.05	2.68	1.35	1.99	2.80	1.45	1.93	2.93	90.82	62.60	72.88	0.00

Sources and Notes:

[1] REVISED DOC Ex. ___ JPK-3, Schedule 6
[2] Yahoo! Finance
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-3, Schedule 5
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (3.68%), then equal to 3.68%',
if [4] is greater than Group Avg. plu St. Dev. (6.06%), then equal to 6.06%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

CORRECTED - Two Growth Rate DCF Analysis - DOC Final Combination Proxy Group
High Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	High Projected Growth Rate	High Expected Dividend Yield	Second Growth Rate		High Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
ALE	62.26	2.08	3.34%	5.50%	3.43%	5.50%		8.93%
AEP	68.11	2.24	3.29%	4.69%	3.37%	4.77%		8.12%
AEE	51.80	1.70	3.28%	6.07%	3.38%	6.07%		9.45%
AVA	43.03	1.37	3.18%	5.00%	3.26%	5.00%		8.26%
CMS	44.28	1.25	2.82%	7.24%	2.93%	7.24%		10.17%
DTE	95.92	2.92	3.04%	5.80%	3.13%	5.80%		8.93%
EE	46.39	1.24	2.67%	6.70%	2.76%	6.70%		9.46%
NWE	61.25	2.00	3.27%	6.50%	3.37%	6.50%		9.87%
PCG	63.20	1.96	3.10%	12.00%	3.29%	8.64%		12.42%
PNM	34.39	0.88	2.56%	9.00%	2.67%	8.64%		11.36%
POR	43.04	1.28	2.97%	6.57%	3.07%	6.57%		9.64%
SCG	72.88	2.30	3.16%	5.40%	3.24%	5.40%		8.64%
Mean			3.06%	6.71%	3.16%	6.40%		9.61%
With Flotation Costs								9.73%
		Average		6.71%				
		Std. Dev.		1.94%			Flotation Costs (F)	3.94%
		Avg. less St. Dev.		4.77%				
		Avg. plus St. Dev		8.64%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ALE	2.14	1.09	1.96	2.25	1.19	1.90	2.38	1.29	1.84	2.51	1.41	1.78	2.65	1.53	1.73	2.79	81.37	53.05	62.26	0.00
AEP	2.29	1.08	2.12	2.40	1.17	2.05	2.51	1.26	1.99	2.63	1.37	1.92	2.75	1.48	1.86	2.88	85.95	58.16	68.11	0.00
AEE	1.75	1.09	1.60	1.86	1.20	1.55	1.97	1.31	1.50	2.09	1.44	1.46	2.22	1.57	1.41	2.35	69.55	44.28	51.80	0.00
AVA	1.40	1.08	1.30	1.47	1.17	1.26	1.55	1.27	1.22	1.63	1.37	1.18	1.71	1.49	1.15	1.79	54.92	36.92	43.03	0.00
CMS	1.30	1.10	1.18	1.39	1.21	1.14	1.49	1.34	1.11	1.60	1.47	1.08	1.71	1.62	1.06	1.84	62.80	38.70	44.28	0.00
DTE	3.00	1.09	2.76	3.18	1.19	2.68	3.36	1.29	2.60	3.56	1.41	2.53	3.76	1.53	2.45	3.98	127.15	82.90	95.92	0.00
EE	1.28	1.09	1.17	1.37	1.20	1.14	1.46	1.31	1.11	1.56	1.44	1.08	1.66	1.57	1.06	1.77	64.15	40.82	46.39	0.00
NWE	2.07	1.10	1.88	2.20	1.21	1.82	2.34	1.33	1.77	2.49	1.46	1.71	2.66	1.60	1.66	2.83	83.91	52.41	61.25	0.00
PCG	2.08	1.12	1.85	2.33	1.26	1.84	2.61	1.42	1.83	2.92	1.60	1.83	3.27	1.80	1.82	3.66	97.00	54.03	63.20	0.00
PNM	0.92	1.11	0.83	1.00	1.24	0.81	1.09	1.38	0.79	1.19	1.54	0.77	1.30	1.71	0.76	1.41	52.11	30.43	34.39	0.00
POR	1.32	1.10	1.21	1.41	1.20	1.17	1.50	1.32	1.14	1.60	1.45	1.11	1.71	1.58	1.08	1.82	59.16	37.34	43.04	0.00
SCG	2.36	1.09	2.17	2.49	1.18	2.11	2.62	1.28	2.05	2.77	1.39	1.99	2.92	1.51	1.93	3.07	94.80	62.64	72.88	0.00

Sources and Notes:
[1] REVISED DOC Ex. ___ JPK-3, Schedule 6
[2] Yahoo! Finance
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-3, Schedule 5
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (4.77%), then equal to 4.77%',
if [4] is greater than Group Avg. plu St. Dev. (8.64%), then equal to 8.64%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:
[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Docket No. E017/GR-15-1033
REVISED DOC Ex. __ JPK-3, Schedule 5

UPDATED -Projected Growth Rates
DOC Combination Proxy Group

Company	Ticker	Zacks	Thomson	Value Line	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate
		[1]	[2]	[3]	[4]	[5]	[6]
ALLETE, Inc.	ALE	5.50%	5.00%	4.00%	4.00%	4.83%	5.50%
American Electric Power Company, Inc.	AEP	4.69%	3.77%	4.50%	3.77%	4.32%	4.69%
Ameren Corporation	AEE	6.07%	5.20%	5.00%	5.00%	5.42%	6.07%
Avista Corporation	AVA	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
CMS Energy Corporation	CMS	6.60%	7.24%	6.00%	6.00%	6.61%	7.24%
DTE Energy Company	DTE	5.80%	5.35%	4.50%	4.50%	5.22%	5.80%
El Paso Electric Company	EE	6.70%	N/A	2.50%	2.50%	4.60%	6.70%
NorthWestern Corporation	NWE	5.00%	5.00%	6.50%	5.00%	5.50%	6.50%
PG&E Corporation	PCG	5.07%	6.04%	12.00%	5.07%	7.70%	12.00%
PNM Resources, Inc.	PNM	7.60%	8.76%	9.00%	7.60%	8.45%	9.00%
Portland General Electric Company	POR	6.45%	6.57%	5.50%	5.50%	6.17%	6.57%
SCANA Corporation	SCG	5.27%	5.40%	4.50%	4.50%	5.06%	5.40%
Average		5.81%	5.76%	5.75%	4.87%	5.74%	6.71%

Sources and notes:
[1] Zacks Investment Research
[2] Thomson Financial Network; Accessed via Yahoo! Finance
[3] Value Line
[4] = min([1], [2], [3])
[5] = average([1], [2], [3])
[6] = max([1], [2], [3])

Docket No. E017/GR-15-1033
REVISED DOC Ex. __ JPK-3, Schedule 6

30-Day Average Closing Prices and Current Dividends
UPDATED - DOC Proxy Group

	ALE	AEP	AEE	AVA	CMS	DTE	EE	NWE	PCG	PNM	POR	SCG
Annualized Dividend	2.080	2.240	1.700	1.370	1.250	2.920	1.240	2.000	1.960	0.880	1.280	2.300
30 Day Average Closing Stock Price	62.26	68.11	51.80	43.03	44.28	95.92	46.39	61.25	63.20	34.39	43.04	72.88
Daily Closing Prices												
7/15/2016	63.74	69.64	52.51	43.44	44.82	97.66	47.52	61.23	64.62	34.26	43.80	73.49
7/14/2016	63.48	69.38	52.24	43.35	44.76	97.09	47.51	61.07	64.20	34.13	43.64	73.67
7/13/2016	64.29	70.01	52.88	44.00	45.03	98.10	46.83	61.52	64.56	34.70	44.06	74.25
7/12/2016	63.67	69.58	52.46	43.53	44.58	97.68	46.26	61.12	63.70	34.53	43.51	73.54
7/11/2016	64.36	70.70	52.94	44.23	45.38	98.96	46.70	62.24	64.73	35.10	44.05	74.87
7/8/2016	64.30	70.71	53.15	44.18	45.51	99.14	46.70	61.68	64.83	35.28	44.36	75.08
7/7/2016	63.68	70.28	52.65	43.85	45.26	98.19	46.46	61.23	64.40	35.17	43.92	74.23
7/6/2016	64.91	71.27	53.77	44.97	46.17	99.95	47.55	63.03	65.39	36.05	44.65	76.12
7/5/2016	65.16	70.81	53.76	44.87	46.08	100.10	47.95	63.33	64.89	35.90	45.04	76.04
7/1/2016	64.58	70.14	53.75	44.49	45.63	99.28	47.54	62.80	64.03	35.24	44.40	75.63
6/30/2016	64.63	70.09	53.58	44.80	45.86	99.12	47.27	63.07	63.92	35.44	44.12	75.66
6/29/2016	63.05	68.72	52.50	43.28	44.84	97.10	46.31	62.10	62.58	34.41	43.06	73.96
6/28/2016	62.52	68.64	52.28	43.22	44.98	96.79	46.38	61.93	62.40	34.22	42.99	73.94
6/27/2016	62.01	68.35	52.31	43.18	44.94	96.49	46.26	61.98	63.17	34.18	42.95	73.39
6/24/2016	61.79	67.26	51.79	42.56	44.36	95.58	45.80	61.40	62.66	33.73	42.28	72.24
6/23/2016	61.78	66.59	51.50	42.19	43.59	94.06	45.73	60.93	62.13	33.63	42.05	71.35
6/22/2016	61.09	66.50	51.26	42.02	43.65	93.75	45.20	60.70	62.15	33.36	42.27	71.48
6/21/2016	61.72	66.77	51.37	42.33	43.71	94.03	45.52	61.39	62.63	33.70	42.52	71.52
6/20/2016	61.79	66.79	51.35	42.38	43.56	93.91	45.61	61.07	62.57	33.62	42.41	71.36
6/17/2016	61.09	67.21	51.27	42.45	43.82	94.38	45.71	61.28	63.02	33.67	42.44	71.42
6/16/2016	61.07	66.88	51.20	42.55	43.71	93.94	45.64	61.08	62.95	33.91	42.58	71.44
6/15/2016	60.54	66.24	50.91	42.24	43.42	94.00	45.66	60.60	62.35	33.99	42.17	71.02
6/14/2016	61.41	66.83	51.31	42.76	43.84	94.98	46.31	61.02	62.98	34.43	42.79	72.25
6/13/2016	60.76	66.55	50.76	42.46	43.31	93.83	46.01	60.49	62.60	34.29	42.49	71.43
6/10/2016	60.81	66.85	50.96	42.46	43.31	93.91	46.30	60.65	63.02	34.44	42.67	71.58
6/9/2016	60.99	66.96	50.89	42.42	43.39	94.05	46.76	60.58	62.98	34.57	42.56	71.67
6/8/2016	60.41	66.20	49.68	41.91	42.83	93.38	46.45	59.84	62.01	34.27	42.05	70.80
6/7/2016	59.82	65.84	49.48	41.51	42.58	92.70	46.08	59.23	61.64	33.79	41.56	70.75
6/6/2016	59.36	65.70	49.54	41.55	42.63	92.59	45.82	59.41	61.30	33.85	41.51	70.99
6/3/2016	59.02	65.81	50.00	41.69	42.82	92.83	45.80	59.35	61.55	33.85	42.18	71.15

Source: Yahoo! Finance

DOC Recommended Flotation Cost Adjustment

Two most recent open market common stock issuances per company, if available

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Company	Date	Shares Issued	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds Per Share	Total Flotation Costs	Gross Equity Issue Before Costs	Net Proceeds	Flotation Cost Percentage
Otter Tail Corporatior	9/18/2008	5,175,000	$30.00	$1.0933	$400,000	$28.83	$6,057,813	$155,250,000	$149,192,187	3.902%
Otter Tail Corporatior	12/7/2004	3,335,000	$25.45	$0.9500	$300,000	$24.41	$3,468,260	$84,875,750	$81,407,490	4.086%
Otter Tail Corporatior	2014	63,305	$28.43	$0.0000	$32,634	$27.92	$32,634	$1,800,000	$1,767,366	1.813%
Otter Tail Corporatior	2015	42,822	$24.99	$0.0000	$7,500	$24.81	$7,500	$1,070,000	$1,062,500	0.701%
Otter Tail Corporatior	2014	262,049	$32.82	$0.0000	$8,500	$32.79	$8,500	$8,600,000	$8,591,500	0.099%
Otter Tail Corporatior	2015	234,702	$31.10	$0.0000	$56,545	$30.86	$56,545	$7,300,000	$7,243,455	0.775%
Otter Tail Corporatior	2014	557,796	$29.69	$0.5937	$663,664	$27.90	$994,842	$16,558,902	$15,564,060	6.008%
Otter Tail Corporatior	2015	95,037	$26.97	$0.5943	$282,675	$23.40	$339,160	$2,562,694	$2,223,534	13.235%
Mean							$1,370,657	$34,752,168		
								WEIGHTED AVERAGE FLOTATION COSTS:		3.944% [10]

Constant Growth Discounted Cash Flow Model Adjusted for Flotation Costs - 30 Day Average Stock Price

		[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]
					Expected Dividend Yield							
Company	Ticker	Annualized Dividend	Average Stock Price	Dividend Yield	Current	Adjusted for Flot. Costs	Zacks Earnings Growth	First Call Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	DCF k(e)	Flotation Adjusted DCF k(e)
ALLETE INC	ALE	$2.08	$62.26	3.34%	3.42%	3.56%	5.50%	5.00%	4.00%	4.83%	8.25%	8.39%
Ameren Corp	AEE	$1.70	$51.80	3.28%	3.37%	3.51%	6.07%	5.20%	5.00%	5.42%	8.79%	8.93%
American Electric Po\	AEP	$2.24	$68.11	3.29%	3.36%	3.50%	4.69%	3.77%	4.50%	4.32%	7.68%	7.82%
Avista Corp	AVA	$1.37	$43.03	3.18%	3.26%	3.40%	5.00%	5.00%	5.00%	5.00%	8.26%	8.40%
CMS Energy Corp	CMS	$1.25	$44.28	2.82%	2.91%	3.03%	6.60%	7.24%	6.00%	6.61%	9.53%	9.65%
DTE Energy Co	DTE	$2.92	$95.92	3.04%	3.12%	3.25%	5.80%	5.35%	4.50%	5.22%	8.34%	8.47%
El Paso Electric Co	EE	$1.24	$46.39	2.67%	2.73%	2.85%	6.70%	n/a	2.50%	4.60%	7.33%	7.45%
Northwestern Corp	NWE	$2.00	$61.25	3.27%	3.35%	3.49%	5.00%	5.00%	6.50%	5.50%	8.85%	8.99%
PG&E Corp	PCG	$1.96	$63.20	3.10%	3.22%	3.35%	5.07%	6.04%	12.00%	7.70%	10.92%	11.05%
PNM Resources Inc.	PNM	$0.88	$34.39	2.56%	2.66%	2.77%	7.60%	8.76%	9.00%	8.45%	11.12%	11.23%
Portland General Ele(	POR	$1.28	$43.04	2.97%	3.06%	3.19%	6.45%	6.57%	5.50%	6.17%	9.24%	9.36%
Scana Corp	SCG	$2.30	$72.88	3.16%	3.23%	3.37%	5.27%	5.40%	4.50%	5.06%	8.29%	8.42%
PROXY GROUP MEAN											8.88%	9.01%

DCF Result Adjusted For Flotation Costs:	9.01%
DCF Result Unadjusted For Flotation Costs:	8.88%
Difference (Flotation Cost Adjustment):	0.13% [22]

Notes:
The proxy group DCF result is adjusted for flotation costs by dividing each company's expected dividend yield by (1 - flotation cost). The flotation cost adjustment is derived as the difference between the unadjusted DCF result and the DCF result adjusted for flotation costs.

[1] Source: Company provided information
[2] Source: Company provided information
[3] Source: Company provided information
[4] Source: Company provided information
[5] Equals [8] / [1]
[6] Equals [4] + ([1] x [3])
[7] Equals [1] x [2]
[8] Equals [7] - [6]
[9] Equals [6] / [7]
[10] Equals average [6] / average [7]
[11] Source: Bloomberg Professional
[12] Source: Bloomberg Professional
[13] Equals [11] / [12]
[14] Equals [3] x (1 + 0.5 x [19])
[15] Equals [4] / (1 - 0.0394)
[16] Source: Zacks
[17] Source: Yahoo! Finance
[18] Source: Value Line
[19] Equals Average([16], [17], [18])
[20] Equals [14] + [19]
[21] Equals [15] + [19]
[22] Equals average [21] - average [20]

DOC CAPM and ECAPM Analyses

	Line No.	Formula/Note	
Risk-free Rate	[1]	DOC Ex.___JPK-4, Schedule 2	1.95%
Thomson First Call Projected S&P Earnings Growth Rate	[2]	DOC Ex.___JPK-4, Schedule 3	7.64%
Dividend Yield on S&P 500	[3]	DOC Ex.___JPK-4, Schedule 4	2.05%
Dividend Yield on S&P 500 with One Half Years' Worth of Growth	[4]	= [3] x (1+[2])^0.5	2.13%
DCF Required Market Return	[5]	= [2] + [4]	9.77%
β	[6]	DOC Ex. ___ JPK-4, Schedule 5	0.75
Required Return for OTP (Simple CAPM)	[7]	= [1] + [6] x ([5] - [1])	7.78%
Flotation Cost Adjustment	[8]	DOC Ex. ___ JPK-3, Schedule 7	0.13%
Simple CAPM with Flotation Costs	[9]	= [7] = [8]	7.91%
Expected Return for MERC (ECAPM)	[10]	= [1]+ 0.25([5]-[1])+ 0.75([6])([5]-[1])	8.28%
Flotation Cost Adjustment	[11]	DOC Ex. ___ JPK-3, Schedule 7	0.13%
ECAPM with Flotation Costs	[12]	= [10] + [11]	8.41%

20-Year Treasury
Constant Maturity Date

Line No.	Date	Rate
		(%)
1.	2016-06-01	2.22
2.	2016-06-02	2.17
3.	2016-06-03	2.09
4.	2016-06-06	2.12
5.	2016-06-07	2.10
6.	2016-06-08	2.08
7.	2016-06-09	2.05
8.	2016-06-10	2.02
9.	2016-06-13	2.01
10.	2016-06-14	2.00
11.	2016-06-15	1.99
12.	2016-06-16	1.96
13.	2016-06-17	1.99
14.	2016-06-20	2.03
15.	2016-06-21	2.07
16.	2016-06-22	2.06
17.	2016-06-23	2.12
18.	2016-06-24	1.96
19.	2016-06-27	1.83
20.	2016-06-28	1.83
21.	2016-06-29	1.86
22.	2016-06-30	1.86
23.	2016-07-01	1.81
24.	2016-07-05	1.72
25.	2016-07-06	1.72
26.	2016-07-07	1.72
27.	2016-07-08	1.69
28.	2016-07-11	1.73
29.	2016-07-12	1.82
30.	2016-07-13	1.77
31.	Average	1.95

Source:
Federal Reserve Bank of St. Louis

Docket No. E017/GR-15-1033
DOC Ex. ___ JPK-4, Schedule 3
Page 1 of 2

Ameren Corporation (AEE) - NYSE

47.83 0.72(1.53%) 4:00PM EDT

After Hours : **47.83** 0.00 (0.00%) 4:28PM EDT

Analyst Estimates

Get Analyst Estimates for: GO

Earnings Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	0.53	1.36	2.50	2.78
No. of Analysts	3.00	3.00	10.00	12.00
Low Estimate	0.51	1.36	2.47	2.72
High Estimate	0.56	1.37	2.54	2.85
Year Ago EPS	0.58	1.41	2.56	2.50

Revenue Est	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Avg. Estimate	1.46B	1.93B	6.28B	6.51B
No. of Analysts	1	1	7	8
Low Estimate	1.46B	1.93B	6.15B	6.43B
High Estimate	1.46B	1.93B	6.53B	6.61B
Year Ago Sales	1.40B	1.83B	6.10B	6.28B
Sales Growth (year/est)	4.50%	5.20%	3.00%	3.50%

Earnings History	Jun 15	Sep 15	Dec 15	Mar 16
EPS Est	0.61	1.30	0.16	0.38
EPS Actual	0.58	1.41	0.12	0.43
Difference	-0.03	0.11	-0.04	0.05
Surprise %	-4.90%	8.50%	-25.00%	13.20%

EPS Trends	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Current Estimate	0.53	1.36	2.50	2.78
7 Days Ago	0.53	1.36	2.50	2.78
30 Days Ago	0.53	1.37	2.52	2.81
60 Days Ago	0.48	1.35	2.53	2.81
90 Days Ago	0.52	1.35	2.52	2.83

EPS Revisions	Current Qtr. Jun 16	Next Qtr. Sep 16	Current Year Dec 16	Next Year Dec 17
Up Last 7 Days	0	0	0	0
Up Last 30 Days	2	1	2	1
Down Last 30 Days	0	0	1	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Est	AEE	Industry	Sector	S&P 500
Current Qtr.	-8.60%	-12.40%	-48.50%	7.80%
Next Qtr.	-3.50%	12.30%	-34.10%	15.20%
This Year	-2.30%	192.40%	35.30%	0.50%
Next Year	11.20%	14.20%	17.20%	12.70%
Past 5 Years (per annum)	1.12%	N/A	N/A	N/A
Next 5 Years (per annum)	5.20%	2.72%	6.18%	7.64%
Price/Earnings (avg. for comparison categories)	18.68	14.79	16.14	15.76
PEG Ratio (avg. for comparison categories)	3.59	2.27	4.11	0.99

Currency in USD.

S&P 500 PE Ratio Shiller PE Ratio 10 Year Treasury Rate S&P 500 Earning

Docket No. E017/GR-15-1033
DOC Ex. ___ JPK-4, Schedule 4
Page 1 of 2

S&P 500 Dividend Yield

Chart Table Share

Current Yield: 2.05% +0.37 bps
11:17 am EDT, Wed Jul 27

Mean: 4.39%
Median: 4.33%
Min: 1.11% (Aug 2000)
Max: 13.84% (Jun 1932)

S&P 500 dividend yield — (12 month dividend per share)/price.

Yields following June 2016 (including the current yield) are estimated based on 12 month dividends through June 2016, as reported by S&P.

Sources:

- Standard & Poor's for current S&P 500 Dividend Yield.
- Robert Shiller and his book Irrational Exuberance for historic S&P 500 Dividend Yields.

See also

- S&P 500 Dividend
- S&P 500 Dividend Growth

Value Line Betas
For Member of
DOC Comparable Group

Ticker	β
ALE	0.80
AEP	0.70
AEE	0.75
AVA	0.75
CMS	0.75
DTE	0.75
EE	0.75
NWE	0.70
PCG	0.70
PNM	0.80
POR	0.80
SCG	0.70
Average	0.75

DOC Comparable Group Year-End Capital Structures for 2015 and Comparison to OTP's Proposed 2016 Capital Structure

Company	Stock Ticker	Short-Term Debt Ratio	Long-Term Debt Ratio	Preferred Stock Ratio	Common Equity Ratio	Total
ALLETE Inc.	ALE	0.05%	46.84%	0.00%	53.12%	100.00%
American Electric Power	AEP	2.07%	51.59%	0.00%	46.34%	100.00%
Ameren Corp	AEE	2.05%	49.61%	0.97%	47.37%	100.00%
Avista Corp	AVA	3.22%	49.86%	0.00%	46.91%	100.00%
CMS Energy Corp	CMS	1.85%	68.69%	0.27%	29.19%	100.00%
DTE Energy Co	DTE	2.69%	50.10%	0.00%	47.21%	100.00%
El Paso Electric Co	EE	6.18%	49.48%	0.00%	44.34%	100.00%
Northwestern Corp	NWE	6.31%	49.73%	0.00%	43.96%	100.00%
PG&E Corp	PCG	2.99%	47.57%	0.74%	48.70%	100.00%
PNM Resources Inc	PNM	6.25%	52.18%	0.29%	41.28%	100.00%
Portland General Electric Co	POR	0.13%	49.33%	0.00%	50.54%	100.00%
Scana Corp	SCG	4.44%	50.10%	0.00%	45.46%	100.00%
Average		3.19%	51.26%	0.19%	45.37%	100.00%
Standard Deviation		2.21%	5.68%	0.33%	5.95%	
Avg. Less One Std. Dev.		0.98%	45.58%	-0.14%	39.41%	
Avg. Plus One Std. Dev.		5.39%	56.93%	0.52%	51.32%	
OTP Proposed 2016 Capital Strucutre		2.60%	44.90%	0.00%	52.50%	100.00%
Does OTP's Proposed % Fall Within One Std. Dev. Of DCG Average?		Yes	No	Yes	No	

OTTER TAIL POWER COMPANY
Docket No: E017/GR-15-1033

Response to: Minnesota Department of Commerce
Analyst: John Kundert
Date Received: 07/18/2016
Date Due: 07/28/2016
Date of Response: 08/02/2016
Responding Witness: Kevin Moug, Chief Financial Officer and Treasurer - (701) 232-3562

Information Request:

Reference: Keven Moug's Direct Testimony, Exhibit (KGM-1), Schedule 5

Please update OTP's forecasted cost of short-term debt.

Attachments: 1

Attachment 1 IR MN-DOC-217.XLSX

Response:

See Attachment 1 to IR MN-DOC-217 for an updated forecasted cost of short-term debt for OTP which reflects actual data for December 31, 2015 through June 30, 2016 and a current updated forecast for the balance of 2016.

OTTER TAIL POWER COMPANY
Electric Utility - State of Minnesota

Docket No. E017/GR-15-1033
Attachment 1 to IR MN-DOC-217
Page 1 of 1

Short-term Debt

Line No.	Month	Month end balances	Monthly Interest Expense	Monthly Fee Expense	Average Short-Term Debt Cost
			Cost of Short-Term Debt		
1	2015 Dec	$21,005,840			
2	2016 Jan	24,000,000	28,690	22,870	
3	2016 Feb	28,000,000	37,382	20,656	
4	2016 Mar	22,055,652	43,787	22,316	
5	2016 Apr	23,134,283	21,329	38,999	
6	2016 May	19,851,119	35,910	23,003	
7	2016 Jun	29,985,186	47,705	21,736	
8	2016 Jul	26,284,532	48,461	24,907	
9	2016 Aug	35,559,182	42,274	24,073	
10	2016 Sep	40,995,600	57,191	21,573	
11	2016 Oct	38,494,981	65,935	47,407	
12	2016 Nov	36,175,279	61,913	23,240	
13	2016 Dec	41,245,838	58,182	20,740	
14	Average	$29,752,884			
15	Total $ Cost		$548,759	$311,521	$860,280
16	Total % Cost		1.84%	1.05%	2.89%

Response to Inforr Docket No. E017/GR-15-1033
DOC Ex. ___ JPK-7
Page 1 of 1

OTTER TAIL POWER COMPANY
Docket No: E017/GR-15-1033

Response to: Minnesota Department of Commerce
Analyst: John Kundert
Date Received: 07/18/2016
Date Due: 07/28/2016
Date of Response: 08/01/2016
Responding Witness: Kevin Moug, Chief Financial Officer and Treasurer - (701) 232-3562

Information Request:

Reference: Keven Moug's Direct Testimony, Exhibit (KGM-1), Schedule 4

Please update OTP's forecasted cost of long-term debt.

Attachments: 0

Response:

There have been no changes with respect to the cost of long-term debt for 2016 (no issuances, no retirements and no changes in interest rates). Accordingly, there is no update to be made.

OTTER TAIL POWER COMPANY
Docket No: E017/GR-15-1033

Response to: Minnesota Department of Commerce
Analyst: Mark Johnson Lerma LaPlante Angela Byrne
Date Received: 07/25/2016
Date Due: 08/04/2016
Date of Response: 08/05/2016
Responding Witness: Kevin Moug, Chief Financial Officer and Treasurer - (701) 232-3562

Information Request:

Reference: Keven Moug's Direct Testimony, Exhibit (KGM-1), Schedule 4

Regarding OTP's Unsecured Series B through D listed on lines 4 through 6 in the schedule, please provide an analysis showing that it is not reasonable, at this time, to refinance one or more of these notes using shorter-term debt.

Attachments: 1

Attachment 1 to IR MN-DOC-219.XLSX

Response:

OTP's Unsecured Series B (2022) Senior Notes, Series C (2027) Senior Notes, and Series D (2037) Senior Notes all have "make whole" provisions. Make whole provisions protect the financial benefit to lenders resulting from the existing interest rates in the event OTP decided to refinance these Notes before the debt is scheduled to come due. The make whole provisions require OTP to make an additional payment based on the net present value of the future interest payments of the notes being refinanced. The make whole amount takes into account the amount of the debt that is refinanced, the debt market conditions at the time of the refinancing, and the remaining time period of the original debt.

As a result of the make whole provisions, OTP would have increased effective interest expenses from refinancing due to a higher level of capital that would need to be financed to pay off the make whole, and the cost of the make whole also increases the effective interest rate as it is amortized over the term of the new bonds as a cost of refinancing. Making an additional payment equal to the net present value of future interest payments would significantly exceed and future interest rate savings that could be achieved by refinancing.

Attachment 1 to IR MN-DOC 219 shows the make whole analysis for the Series B, C, and D Notes and that the effective interest rates would be increased by a refinancing even with lower refinanced ("New Coupon") rates.

Docket No. E017/GR-15-1033

Docket No. E017/GR-15-1033
Attachment 1 to IR MN-DOC-219

Attachment 1 to IR-MN-DOC 219
Make Whole Analysis of OTP Series B, C, and D Notes

	Series B	Series C	Series D
Original Coupon	6.15%	6.37%	6.47%
Original Principal	$ 30,000,000.00	$ 42,000,000.00	$ 50,000,000.00
Maturity	Aug-22	Aug-27	Aug-37
New Coupon	2.54%	3.03%	3.51%
Remaining Average Life	6.14	11.14	21.14
Make Whole	$ 12,085,473.53	$ 29,532,211	$ 68,095,592
New Debt Level	$ 42,085,473.53	$ 71,532,211.46	$ 118,095,591.82
Make Whole Amortization	$ 1,968,318.16	$ 2,953,221.15	$ 6,809,559.18
New Annual Interest	$ 1,068,971.03	$ 2,167,426.01	$ 4,145,155.27
Effective Interest Rate	7.22%	7.16%	9.28%

OTTER TAIL POWER COMPANY
Docket No: E017/GR-15-1033

Response to: Minnesota Department of Commerce
Analyst: John Kundert
Date Received: 06/01/2016
Date Due: 06/13/2016
Date of Response: 06/13/2016
Responding Witness: Robert B. Hevert, Managing Partner, Sussex Economic Advisors (508) 202-7923

Information Request:

Reference: Direct Testimony of Mr. Robert B. Hevert, page 11

a. Please provide a complete list of the companies Value Line classifies as Electric Utilities.

b. Mr. Hevert's first screen was the elimination of any company that didn't pay quarterly cash dividends.

    a. Identify the time period this criterion covered, (i.e. most recent quarter, most recent annual reporting period).
    b. The list of companies eliminated by this screen.

c. Mr. Hevert's second screen was the elimination of any company which has not been covered by at least two recognized utility equity analysts. Regarding this screen, please provide the following information:
    a. The list of companies eliminated by this screen.
    b. The source providing the list of utility equity analysts covering each of the companies included in your group.

d. Mr. Hevert's third screen was the elimination of any company that had did not have investment grade senior unsecured bond and/or corporate credit ratings from Standard and Poor's. Please provide the definition of the term "investment grade senior

e. unsecured bond and/or corporate credit ratings" used to make this determination. Please also provide the list of companies eliminated by this screen.
f. Mr. Hevert's fourth screen eliminated any company that were not vertically integrated. Please provide the list of companies eliminated by this screen.
g. Mr. Hevert's fifth screen excluded companies whose regulated operating income over the three most recent reported fiscal years comprised less than 60 percent of the respective totals for that company. Please provide the list of companies eliminated by this screen.
h. Mr. Hevert's sixth screen eliminated companies with a market capitalization greater than $10 billion. Please provide the list of companies eliminated by this screen.
i. Mr. Hevert's seventh screen eliminated companies with more than 250 customers per square mile. Regarding this screen, please provide the following information:
    a. The list of companies eliminated by this screen.
    b. The source providing the estimated number of customers per square mile of service territory.
j. Mr. Hevert's eighth screen eliminated companies that were currently known to be party to a merger or some other significant transaction. Please provide a list of companies eliminated by this screen.
k. Mr. Hevert's ninth screen excluded companies with discounted cash flow results with a cost on equity of less than 8.00 percent. Regarding this screen, please provide the following information:
    a. The list of companies eliminated by this screen.
    b. The citation(s) that support this convention.

Attachments: 1

Attachment 1 to IR MN-DOC-203_PUBLIC.xlsx

Response:

a. A list of all companies Value Line classifies as Electric Utilities is shown in Column A of the "Initial Screen" tab of Attachment 1 to DOC-IR-203 (which was also included in Attachment 1 to IR MN-OAG-102).

b.
    a. Mr. Hevert did not consider a specific timeframe regarding the payment of dividends, but instead considered two criteria when assessing companies' consistent payment of quarterly dividends: (1) the company must display a sufficient history of quarterly dividend payments such that investors' expectations can be based on consistent quarterly dividend payments; and (2) the company has not recently

decreased its quarterly dividend payment. This criterion is necessary because the DCF model requires consistent dividend payments.

b. El Paso Electric was eliminated by this screen as shown in Column D of the "Initial Screen" tab of Attachment 1 to IR MN-DOC-203.

c.

a. MGE Energy, Inc. was eliminated by this screen, as shown in Column E of the "Initial Screen" tab of Attachment 1 to IR MN-DOC-203.

b. Both consensus estimate providers (Zacks and Yahoo! Finance) list the number of analysts contributing to earnings estimates but the identities of utility equity analysts are not provided.

d. Investment grade is typically defined as BBB-, and above. Mr. Hevert used this definition in his proxy group screening.

e. No company was eliminated by the investment grade debt screen, as shown in Column F of the "Initial Screen" tab of Attachment 1 to IR MN-DOC-203.

f. CenterPoint Energy, Inc., Consolidated Edison, Inc., Eversource Energy, FirstEnergy Corp., ITC Holdings Corp., and Pepco Holdings, Inc. were eliminated by the vertical integration screen, as shown in Column G of the "Initial Screen" tab of Attachment 1 to IR MN-DOC-203.

g. Exelon Corporation, PPL Corporation, and Public Service Enterprise Group Incorporated were eliminated by the 60 percent regulated operating income screen, as shown in Column H of the "Initial Screen" tab of Attachment 1 to IR MN-DOC-203. In addition, Sempra Energy, and Vectren Corporation were eliminated by the 60 percent electric operating income screen, as shown in Column I of the "Initial Screen" tab of Attachment 1 to IR MN-DOC-203.

h. Of the companies that had passed all prior screens, American Electric Power Company, Inc., Dominion Resources, Inc., DTE Energy Company, and Xcel Energy, Inc. were eliminated by the $10 billion market capitalization screen, as shown on in Column D of the "Final Screen" tab of Attachment 1 to IR MN-DOC-203.

i.

a. Of the companies that had passed all prior screens, Pinnacle West Capital Corporation and Portland General Electric Company were eliminated by the customer density screen, as shown in Column C of the "Final Screen" tab of Attachment 1 to IR MN-DOC-203. DTE Energy Company failed this screen and also failed the $10 billion market capitalization screen, as shown in Columns C and D of the "Final Screen" tab of Attachment 1 to IR MN-DOC-203.

b. The number of customers and size of service territory were provided by SNL Financial. The source data is included on the "Size and Service Area" tab of Attachment 1 to IR MN-DOC-203.

j. The companies eliminated by this screen include Black Hills Corporation, Cleco Corporation, Duke Energy Corporation, Edison International, Empire District Electric Company, Entergy Corporation, Exelon Corporation, Hawaiian Electric Industries Inc., NextEra Energy, Inc., Pepco Holdings, Inc., PG&E Corporation, Southern Company, TECO Energy Inc., and Wisconsin Energy Corporation. Details for each transaction are included on the "Transaction Data" tab of Attachment 1 to IR MN-DOC-203. In addition, since the filing of Mr. Hevert's Direct Testimony, Great Plains Energy Inc. (included in Mr. Hevert's proxy group) announced its plan to acquire Westar Energy, Inc. which will now cause both companies to fail this screen.

k.

a. IDACORP, Westar Energy Inc., and OGE Energy Corp. failed the 8.00 percent minimum financial reasonableness screen, as shown in Column E of the "Final Screen" tab of Attachment 1 to IR MN-DOC-203. Calculations supporting this screen are shown on the "Preliminary DCF Results" tab of Attachment 1 to IR MN-DOC-203. The minimum financial reasonableness screen has been previously accepted by Administrative Law Judges and Commission.

b. In two recent cases (Docket No. E-002/GR-13-868 and Docket No. E-002/GR- 12-96) the Commission has adopted ROEs that were calculated by explicitly eliminating DCF results below 8.00 percent which do not pass the test of financial reasonableness.

In Docket No. E-002/GR-13-868, the Commission's Findings of Fact, Conclusions of Law and Order (May 8, 2015) state (at page 57):

> "The Commission concurs with the Administrative Law Judge that the Company's and the Department's cost-of-equity studies are methodologically transparent, analytically sound, and ably executed. Together they represent the best evidence in the record on the cost of equity and provide a workable framework for determining where to set the cost of equity in this case."

The December 14, 2014 ALJ Report in Docket No. E-002/GR-13-868 (in which the Commission concurred) notes that: (i) the Department eliminated five electric companies with ROEs below 8.00 percent because these companies did not pass the financial reasonableness test (at Finding 280); (ii) the Department eliminated two combination companies with DCF results lower than 8.00 percent (at Finding 283); and (iii) the Company eliminated two electric companies with ROEs below 8.00 percent (at Finding 253).

In Docket No. E-002/GR-12-961, the Commission's Findings of Fact, Conclusions of Law and Order (September 3, 2013) states (at page 12):

> "The Commission concurs with the Administrative Law Judge that the Department's position is best supported by the record... .")

The December 14, 2014 ALJ Report in Docket No. E-002/GR-13-868 (in which the Commission concurred) notes that: (i) the Department eliminated four electric companies with DCF results below 8 percent from the initial electric comparable group because did not pass the financial reasonableness test (at Finding 310); (ii) the Department added back two of these companies in the updated analysis because the results were above 8 percent (Finding 360); and (iii) the Department eliminated 1 combination company in its updated analysis because the mean DCF was below 8 percent (Finding 360).

OTP has taken reasonable efforts to maintain the secrecy of the information marked as PROTECTED DATA in Attachment 1, which derive independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use (the "Protected Data"). The Protected Data is therefore "trade secret information" and "nonpublic data" under Minn. Stat. § 13.37.

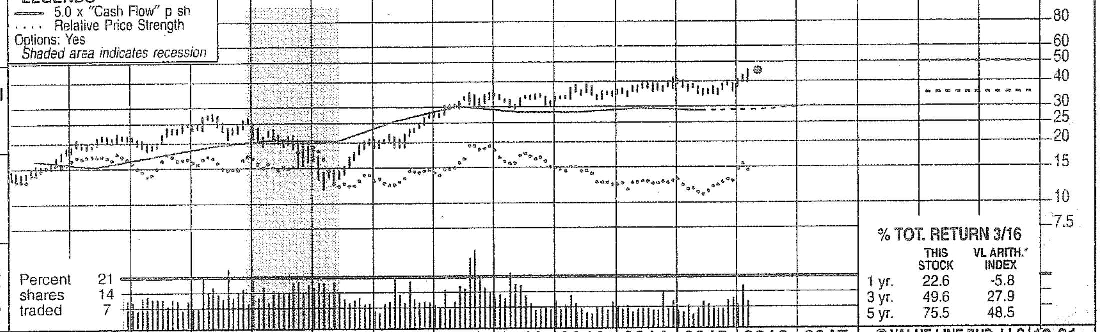
EL PASO ELECTRIC NYSE-EE

RECENT PRICE 45.41 | P/E RATIO 23.7 (Trailing: 22.4 Median: 15.0)

TIMELINESS 2 Raised 4/1/16
SAFETY 2 Raised 5/11/07
TECHNICAL 2 Raised 4/29/16
BETA .75 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High:	22.4	25.0	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3	46.6
Low:	17.8	18.2	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8	37.2

Target Price Range 2019 | 2020 | 2021



2019-21 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+10%)	5%
Low	35	(-25%)	-3%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	5	0	1	12	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2015	3Q2015	4Q2015
to Buy	76	78	87
to Sell	71	63	53
Hld's(000)	39499	39588	39215

% TOT. RETURN 3/16

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.6	-5.8
3 yr.	49.6	27.9
5 yr.	75.5	48.5

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	© VALUE LINE PUB. LLC	19-21
13.70	15.40	13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.74	21.01	*21.60*	*22.75*	Revenues per sh	*24.50*
3.21	3.43	2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.87	5.75	*5.80*	*6.10*	"Cash Flow" per sh	*7.00*
1.09	1.27	.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.27	2.03	*2.05*	*2.20*	Earnings per sh A	*2.50*
--	--	--	--	--	--	--	--	--	--	--	.66	.97	1.05	1.11	1.17	*1.23*	*1.23*	Div'd Decl'd per sh B	*1.50*
1.70	1.85	1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	8.50	8.55	*7.75*	*6.40*	Cap'l Spending per sh	*7.25*
8.05	9.01	9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	25.13	*25.90*	*26.80*	Book Value per sh C	*29.50*
51.20	49.99	49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.36	40.44	*40.55*	*40.65*	Common Shs Outst'g D	*41.00*
10.6	11.0	23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	18.3	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.69	.56	1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.86	.92	*Value Line*		Relative P/E Ratio	*1.05*
--	--	--	--	--	--	--	--	--	--	--	2.1%	3.0%	3.0%	3.0%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 12/31/15
Total Debt $1276.0 mill. **Due in 5 Yrs** $270.0 mill.
LT Debt $1134.3 mill. **LT Interest** $68.2 mill.
(LT interest earned: 2.4x)

Pension Assets-12/15 $260.0 mill. **Oblig.** $325.7 mill.

Pfd Stock None

Common Stock 40,443,817 shs.

MARKET CAP: $1.8 billion (Mid Cap)

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		19-21
816.5	877.4	1038.9	828.0	877.3	918.0	852.9	890.4	917.5	849.9	*875*	*925*	Revenues ($mill)	*1000*
61.4	74.8	77.6	66.9	90.3	103.5	90.8	88.6	91.4	81.9	*85.0*	*90.0*	Net Profit ($mill)	*100*
29.8%	31.6%	32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	31.0%	29.9%	*31.0%*	*31.0%*	Income Tax Rate	*31.0%*
8.0%	15.9%	20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	30.8%	27.5%	*24.0%*	*17.0%*	AFUDC % to Net Profit	*15.0%*
51.5%	49.6%	53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	53.5%	52.7%	*55.0%*	*55.5%*	Long-Term Debt Ratio	*57.0%*
48.5%	50.4%	46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	46.5%	47.3%	*45.0%*	*44.5%*	Common Equity Ratio	*43.0%*
1195.8	1321.6	1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	2118.4	2150.8	*2335*	*2450*	Total Capital ($mill)	*2800*
1332.2	1450.6	1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	2488.4	2695.5	*2860*	*2960*	Net Plant ($mill)	*3325*
6.6%	7.1%	6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	5.7%	5.3%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.3%	8.1%	*8.0%*	*8.0%*	Return on Com Equity E	*8.5%*
10.6%	11.2%	11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	4.8%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*3.0%*
--	--	--	--	--	26%	43%	47%	49%	57%	*59%*	*58%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2013	2014	2015
% Change Retail Sales (KWH)	+.4	-1.6	+2.3
Avg. Indust. Use (MWH)	21908	21505	21687
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1852	1879	2055
Peak Load, Summer (Mw)	1750	1766	1794
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.3	+1.3	+1.4
Fixed Charge Cov. (%)	280	251	218

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '19-'21
Revenues	3.5%	1.0%	*2.0%*
"Cash Flow"	6.5%	5.0%	*3.5%*
Earnings	12.0%	4.0%	*2.5%*
Dividends	--	--	*5.0%*
Book Value	8.0%	7.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	177.3	240.1	282.7	190.3	890.4
2014	185.5	251.8	283.6	196.6	917.5
2015	163.8	219.5	289.7	176.9	849.9
2016	*170*	*235*	*290*	*180*	*875*
2017	*180*	*245*	*305*	*195*	*925*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.19	.72	1.26	.03	2.20
2014	.11	.75	1.30	.10	2.27
2015	.09	.52	1.40	.02	2.03
2016	*Nil*	*.65*	*1.25*	*.15*	*2.05*
2017	*.10*	*.65*	*1.30*	*.15*	*2.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.22	.25	.25	.25	.97
2013	.25	.265	.265	.265	1.05
2014	.265	.28	.28	.28	1.11
2015	.28	.295	.295	.295	1.17
2016	.295				

BUSINESS: El Paso Electric Company (EPE) provides electric service to 405,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 47%; gas, 34%; coal, 6%; purchased, 13%. Fuel costs: 28% of revenues. '15 reported depreciation rate: 2.6%. Has about 1,000 employees. Chairman: Charles A. Yamarone. President & CEO: Mary Kipp. Incorporated: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, Texas 79901. Tel.: 915-543-5711. Internet: www.epelectric.com.

El Paso Electric Company has reached a settlement of its rate case in Texas. The utility is trying to place units 1 and 2 of what will be a four-unit gas-fired generating station into the rate base, along with other capital expenditures since its last rate case. EPE had requested a $70.5 million tariff hike, based on a 10.1% return on a common-equity ratio of 49.52%. It reached a settlement with the city of El Paso that calls for a $37 million increase, an $8.5 million reduction in depreciation (based on lower depreciation rates), and the potential for an additional $8 million boost for costs associated with the EPE's stake in a coal-fired plant, which the company hopes to sell by July. However, there is no assurance that the Texas regulators will approve the settlement, especially since four intervenors oppose it. There is no time frame for the commission to put forth its ruling, but an interim rate increase took effect at the start of April.

A rate case is pending in New Mexico, as well. EPE is seeking a tariff hike of $6.4 million, based on a return of 9.95% on a common-equity ratio of 49.29%. A hearing examiner recommended a raise of just $640,000, based on a 9.6% ROE. An order is expected in June.

We think earnings will be relatively flat this year. In 2015, the effects of regulatory lag hurt the company. On the other hand, weather patterns were favorable for the company, especially in the third quarter. We have trimmed our 2016 estimate by a nickel a share, to $2.05, because the March period was probably weaker than we previously expected. Note that management has not put forth earnings guidance for 2016 because the aforementioned rate cases are pending.

We forecast higher profits in 2017. The company will benefit from a full year of rate relief it gets in 2016.

We think the board of directors will raise the dividend next month. This has been the pattern in recent years. We look for a $0.015-a-share (5.1%) hike in the quarterly disbursement, the same as in the past three years.

The dividend yield of this timely stock is on the low side for a utility. Total return potential to 2019-2021 is low, too.

Paul E. Debbas, CFA *April 29, 2016*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '01, (4¢); '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. '14 earnings don't add to full-year total due to rounding. Next earnings report due early May. (B) Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. (C) Incl. deferred charges. In '15: $115.1 mill., $2.85/sh. (D) In millions. (E) Rate allowed on common equity in TX in '12: none specified; in NM in '10: none specified; earned on average common equity, '15: 8.2%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	85

UPDATED - Constant Growth DCF Analysis - OTP Proxy Group - Base Case

Company	Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
ALLETE, Inc.	ALE	62.26	2.08	3.34%	4.00%	4.83%	5.50%	3.41%	3.42%	3.43%	7.41%	8.25%	8.93%
Ameren Corporation	AEE	51.80	1.70	3.28%	5.00%	5.42%	6.07%	3.36%	3.37%	3.38%	8.36%	8.79%	9.45%
Alliant Energy Corporation	LNT	39.38	1.17	2.97%	6.00%	6.22%	6.60%	3.06%	3.06%	3.07%	9.06%	9.29%	9.67%
Avista Corporation	AVA	43.03	1.37	3.18%	5.00%	5.00%	5.00%	3.26%	3.26%	3.26%	8.26%	8.26%	8.26%
CMS Energy Corporation	CMS	44.28	1.25	2.82%	6.00%	6.61%	7.24%	2.91%	2.92%	2.93%	8.91%	9.53%	10.17%
NorthWestern Corporation	NWE	61.25	2.00	3.27%	5.00%	5.50%	6.50%	3.35%	3.36%	3.37%	8.35%	8.86%	9.87%
PNM Resources Inc	PNM	34.39	0.88	2.56%	7.60%	8.45%	9.00%	2.66%	2.67%	2.67%	10.26%	11.12%	11.67%
Scana Corp	SCG	72.88	2.30	3.16%	4.50%	5.06%	5.40%	3.23%	3.24%	3.24%	7.73%	8.29%	8.64%
Mean				3.07%	5.39%	5.89%	6.41%	3.15%	3.16%	3.17%	8.54%	9.05%	9.58%
Required ROE including flotation cost adjustment											8.67%	9.18%	9.71%
Flotation Costs											3.94%		

Sources and Notes:
[1] REVISED DOC Ex. __ JPK-11, Schedule 16-a
[2] REVISED DOC Ex. __ JPK-11, Schedule 16-a
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-11, Schedule 15-a
[5] REVISED DOC Ex. __ JPK-11, Schedule 15-a
[6] REVISED DOC Ex. __ JPK-11, Schedule 15-a
[7] = [3] x (1 + 0.5 x [4])
[8] = [3] x (1 + 0.5 x [5])
[9] = [3] x (1 + 0.5 x [6])
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

UPDATED - Two Growth Rate DCF Analysis - OTP Proxy Group - Base Case
Mean Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Mean Projected Growth Rate	Mean Expected Dividend Yield	Second Growth Rate		Mean Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
ALE	62.26	2.08	3.34%	4.83%	3.42%	4.83%		8.25%
AEE	51.80	1.70	3.28%	5.42%	3.37%	5.42%		8.79%
LNT	39.38	1.17	2.97%	6.22%	3.06%	6.22%		9.29%
AVA	43.03	1.37	3.18%	5.00%	3.26%	5.00%		8.26%
CMS	44.28	1.25	2.82%	6.61%	2.92%	6.61%		9.53%
NWE	61.25	2.00	3.27%	5.50%	3.36%	5.50%		8.86%
PNM	34.39	0.88	2.56%	8.45%	2.67%	7.02%		9.85%
SCG	72.88	2.30	3.16%	5.06%	3.24%	5.06%		8.29%
Mean			3.07%	5.89%	3.16%	5.71%		8.89%
With Flotation Costs								9.02%
		Average		5.89%				
		Std. Dev.		1.13%			Flotation Costs (F)	3.94%
		Avg. less St. Dev.		4.76%				
		Avg. plus St. Dev		7.02%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ALE	2.13	1.08	1.97	2.23	1.17	1.91	2.34	1.27	1.85	2.45	1.37	1.79	2.57	1.49	1.73	2.70	78.83	53.02	62.26	0.00
AEE	1.75	1.09	1.60	1.84	1.18	1.56	1.94	1.29	1.51	2.05	1.40	1.46	2.16	1.52	1.42	2.27	67.46	44.26	51.80	0.00
LNT	1.21	1.09	1.10	1.28	1.19	1.07	1.36	1.31	1.04	1.45	1.43	1.01	1.54	1.56	0.99	1.63	53.25	34.16	39.38	0.00
AVA	1.40	1.08	1.30	1.47	1.17	1.26	1.55	1.27	1.22	1.63	1.37	1.18	1.71	1.49	1.15	1.79	54.92	36.92	43.03	0.00
CMS	1.29	1.10	1.18	1.38	1.20	1.15	1.47	1.31	1.12	1.56	1.44	1.09	1.67	1.58	1.06	1.78	60.99	38.69	44.28	0.00
NWE	2.06	1.09	1.89	2.17	1.18	1.83	2.29	1.29	1.77	2.41	1.40	1.72	2.55	1.53	1.67	2.69	80.05	52.37	61.25	0.00
PNM	0.92	1.10	0.83	0.99	1.21	0.82	1.08	1.33	0.81	1.17	1.46	0.80	1.27	1.60	0.79	1.38	48.51	30.32	34.39	0.00
SCG	2.36	1.08	2.18	2.48	1.17	2.11	2.60	1.27	2.05	2.73	1.38	1.99	2.87	1.49	1.93	3.02	93.26	62.62	72.88	0.00

Sources and Notes:
[1] REVISED DOC Ex. __ JPK-11, Schedule 16-a
[2] REVISED DOC Ex. __ JPK-11, Schedule 16-a
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-11, Schedule 15-a
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (4.76%), then equal to 4.76%',
if [4] is greater than Group Avg. plu St. Dev. (7.02%), then equal to 7.02%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:
[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

UPDATED - Constant Growth DCF Analysis - OTP Proxy Group - Consistently Pays Quarterly Dividend Criterion Scenario

Company	Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
ALLETE, Inc.	ALE	62.26	2.08	3.34%	4.00%	4.83%	5.50%	3.41%	3.42%	3.43%	7.41%	8.25%	8.93%
Ameren Corporation	AEE	51.80	1.70	3.28%	5.00%	5.42%	6.07%	3.36%	3.37%	3.38%	8.36%	8.79%	9.45%
Alliant Energy Corporation	LNT	39.38	1.17	2.97%	6.00%	6.22%	6.60%	3.06%	3.06%	3.07%	9.06%	9.29%	9.67%
Avista Corporation	AVA	43.03	1.37	3.18%	5.00%	5.00%	5.00%	3.26%	3.26%	3.26%	8.26%	8.26%	8.26%
CMS Energy Corporation	CMS	44.28	1.25	2.82%	6.00%	6.61%	7.24%	2.91%	2.92%	2.93%	8.91%	9.53%	10.17%
El Paso Electric Company	**EE**	**46.39**	**1.24**	**2.67%**	**2.50%**	**4.60%**	**6.70%**	**2.71%**	**2.73%**	**2.76%**	**5.21%**	**7.33%**	**9.46%**
Northwestern Corp	NWE	61.25	2.00	3.27%	5.00%	5.00%	5.00%	3.35%	3.35%	3.35%	8.35%	8.35%	8.35%
PNM Resources Inc	PNM	34.39	0.88	2.56%	7.60%	8.45%	9.00%	2.66%	2.67%	2.67%	10.26%	11.12%	11.67%
Scana Corp	SCG	72.88	2.30	3.16%	4.50%	5.06%	5.40%	3.23%	3.24%	3.24%	7.73%	8.29%	8.64%
Mean				3.03%	5.07%	5.69%	6.28%	3.10%	3.11%	3.12%	8.17%	8.80%	9.40%
Required ROE including flotation cost adjustment											8.30%	8.93%	9.53%
Flotation Costs											3.94%		

Sources and Notes:
[1] REVISED DOC Ex. __ JPK-11, Schedule 16 - b
[2] REVISED DOC Ex. __ JPK-11, Schedule 16 - b
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-11, Schedule 15 - b
[5] REVISED DOC Ex. __ JPK-11, Schedule 15 - b
[6] REVISED DOC Ex. __ JPK-11, Schedule 15 - b
[7] = [3] x (1 + 0.5 x [4])
[8] = [3] x (1 + 0.5 x [5])
[9] = [3] x (1 + 0.5 x [6])
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

UPDATED - Two Growth Rate DCF Analysis - OTP Proxy Group Consistently Pays Quarterly Dividends Criterion Scenario
Mean Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Mean Projected Growth Rate	Mean Expected Dividend Yield	Second Growth Rate	Mean Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
ALE	62.26	2.08	3.34%	4.83%	3.42%	4.83%	8.25%
AEE	51.80	1.70	3.28%	5.42%	3.37%	5.42%	8.79%
LNT	39.38	1.17	2.97%	6.22%	3.06%	6.22%	9.29%
AVA	43.03	1.37	3.18%	5.00%	3.26%	5.00%	8.26%
CMS	44.28	1.25	2.82%	6.61%	2.92%	6.61%	9.53%
EE	46.39	1.24	2.67%	4.60%	2.73%	4.60%	7.33%
NWE	61.25	2.00	3.27%	5.00%	3.35%	5.00%	8.35%
PNM	34.39	0.88	2.56%	8.45%	2.67%	6.85%	9.71%
SCG	72.88	2.30	3.16%	5.06%	3.24%	5.06%	8.29%
Mean			3.03%	5.69%	3.11%	5.51%	8.65%
With Flotation Costs							8.77%
		Average		5.69%			
		Std. Dev.		1.16%		Flotation Costs (F)	3.94%
		Avg. less St. Dev.		4.53%			
		Avg. plus St. Dev		6.85%			

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ALE	2.13	1.08	1.97	2.23	1.17	1.91	2.34	1.27	1.85	2.45	1.37	1.79	2.57	1.49	1.73	2.70	78.83	53.02	62.26	0.00
AEE	1.75	1.09	1.60	1.84	1.18	1.56	1.94	1.29	1.51	2.05	1.40	1.46	2.16	1.52	1.42	2.27	67.46	44.26	51.80	0.00
LNT	1.21	1.09	1.10	1.28	1.19	1.07	1.36	1.31	1.04	1.45	1.43	1.01	1.54	1.56	0.99	1.63	53.25	34.16	39.38	0.00
AVA	1.40	1.08	1.30	1.47	1.17	1.26	1.55	1.27	1.22	1.63	1.37	1.18	1.71	1.49	1.15	1.79	54.92	36.92	43.03	0.00
CMS	1.29	1.10	1.18	1.38	1.20	1.15	1.47	1.31	1.12	1.56	1.44	1.09	1.67	1.58	1.06	1.78	60.99	38.69	44.28	0.00
EE	1.27	1.07	1.18	1.33	1.15	1.15	1.39	1.24	1.12	1.45	1.33	1.09	1.52	1.42	1.07	1.59	58.08	40.77	46.39	0.00
NWE	2.05	1.08	1.89	2.15	1.17	1.83	2.26	1.27	1.78	2.37	1.38	1.72	2.49	1.49	1.67	2.62	78.17	52.35	61.25	0.00
PNM	0.92	1.10	0.84	0.99	1.20	0.83	1.08	1.32	0.82	1.17	1.45	0.81	1.27	1.59	0.80	1.38	48.16	30.30	34.39	0.00
SCG	2.36	1.08	2.18	2.48	1.17	2.11	2.60	1.27	2.05	2.73	1.38	1.99	2.87	1.49	1.93	3.02	93.26	62.62	72.88	0.00

Sources and Notes:

[1] REVISED DOC Ex. __ JPK-11, Schedule 16 - b
[2] REVISED DOC Ex. __ JPK-11, Schedule 16 - b
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-11, Schedule 15 - b
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (4.53%), then equal to 4.53%',
if [4] is greater than Group Avg. plu St. Dev. (6.85%), then equal to 6.85%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

CORRECTED - Constant Growth DCF Analysis - OTP Proxy Group -Symmetrical Credit Rating Criterion Scenario

Company	Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
ALLETE, Inc.	ALE	62.26	2.08	3.34%	4.00%	4.83%	5.50%	3.41%	3.42%	3.43%	7.41%	8.25%	8.93%
Ameren Corporation	AEE	51.80	1.70	3.28%	5.00%	5.42%	6.07%	3.36%	3.37%	3.38%	8.36%	8.79%	9.45%
Avista Corporation	AVA	43.03	1.37	3.18%	5.00%	5.00%	5.00%	3.26%	3.26%	3.26%	8.26%	8.26%	8.26%
CMS Energy Corporation	CMS	44.28	1.25	2.82%	6.00%	6.61%	7.24%	2.91%	2.92%	2.93%	8.91%	9.53%	10.17%
NorthWestern Corporation	NWE	61.25	2.00	3.27%	5.00%	5.50%	6.50%	3.35%	3.36%	3.37%	8.35%	8.86%	9.87%
PNM Resources, Inc.	PNM	34.39	0.88	2.56%	7.60%	8.45%	9.00%	2.66%	2.67%	2.67%	10.26%	11.12%	11.67%
Scana Corp	SCG	72.88	2.30	3.16%	4.50%	5.06%	5.40%	3.23%	3.24%	3.24%	7.73%	8.29%	8.64%
Mean				3.09%	5.30%	5.84%	6.39%	3.17%	3.18%	3.18%	8.47%	9.02%	9.57%
Required ROE including flotation cost adjustment											8.60%	9.15%	9.70%
Flotation Costs											3.94%		

Sources and Notes:
[1] REVISED DOC Ex. __ JPK-11, Schedule 16 - c
[2] REVISED DOC Ex. __ JPK-11, Schedule 16 - c
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-11, Schedule 15 - c
[5] REVISED DOC Ex. __ JPK-11, Schedule 15 - c
[6] REVISED DOC Ex. __ JPK-11, Schedule 15 - c
[7] = [3] x (1 + 0.5 x [4])
[8] = [3] x (1 + 0.5 x [5])
[9] = [3] x (1 + 0.5 x [6])
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

CORRECTED - Two Growth Rate DCF Analysis - OTP Proxy Group - Symmetrical Credit Rating Criterion Scenario
Mean Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Mean Projected Growth Rate	Mean Expected Dividend Yield	Second Growth Rate		Mean Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
ALE	62.26	2.08	3.34%	4.83%	3.42%	4.83%		8.25%
AEE	51.80	1.70	3.28%	5.42%	3.37%	5.42%		8.79%
AVA	43.03	1.37	3.18%	5.00%	3.26%	5.00%		8.26%
CMS	44.28	1.25	2.82%	6.61%	2.92%	6.61%		9.53%
NWE	61.25	2.00	3.27%	5.50%	3.36%	5.50%		8.86%
PNM	34.39	0.88	2.56%	8.45%	2.67%	7.04%		9.87%
SCG	72.88	2.30	3.16%	5.06%	3.24%	5.06%		8.29%
Mean			3.09%	5.84%	3.18%	5.64%		8.84%
With Flotation Costs								8.97%
		Average		5.84%				
		Std. Dev.		1.20%			Flotation Costs (F)	3.94%
		Avg. less St. Dev.		4.64%				
		Avg. plus St. Dev		7.04%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ALE	2.13	1.08	1.97	2.23	1.17	1.91	2.34	1.27	1.85	2.45	1.37	1.79	2.57	1.49	1.73	2.70	78.83	53.02	62.26	0.00
AEE	1.75	1.09	1.60	1.84	1.18	1.56	1.94	1.29	1.51	2.05	1.40	1.46	2.16	1.52	1.42	2.27	67.46	44.26	51.80	0.00
AVA	1.40	1.08	1.30	1.47	1.17	1.26	1.55	1.27	1.22	1.63	1.37	1.18	1.71	1.49	1.15	1.79	54.92	36.92	43.03	0.00
CMS	1.29	1.10	1.18	1.38	1.20	1.15	1.47	1.31	1.12	1.56	1.44	1.09	1.67	1.58	1.06	1.78	60.99	38.69	44.28	0.00
NWE	2.06	1.09	1.89	2.17	1.18	1.83	2.29	1.29	1.77	2.41	1.40	1.72	2.55	1.53	1.67	2.69	80.04	52.37	61.24	0.00
PNM	0.92	1.10	0.83	0.99	1.21	0.82	1.08	1.33	0.81	1.17	1.46	0.80	1.27	1.60	0.79	1.38	48.55	30.32	34.39	0.00
SCG	2.36	1.08	2.18	2.48	1.17	2.11	2.60	1.27	2.05	2.73	1.38	1.99	2.87	1.49	1.93	3.02	93.26	62.62	72.88	0.00

Sources and Notes:

[1] REVISED DOC Ex. __ JPK-11, Schedule 16 - c
[2] REVISED DOC Ex. __ JPK-11, Schedule 16 - c
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-11, Schedule 15 - c
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (4.64%), then equal to 4.64%',
if [4] is greater than Group Avg. plu St. Dev. (7.04%), then equal to 7.04%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

CORRECTED Constant Growth DCF Analysis - OTP Proxy Group - $10 Billion Market Capitalization Criterion Scenario

Company	Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
ALLETE, Inc.	ALE	62.26	2.08	3.34%	4.00%	4.83%	5.50%	3.41%	3.42%	3.43%	7.41%	8.25%	8.93%
Ameren Corporation	AEE	51.80	1.70	3.28%	5.00%	5.42%	6.07%	3.36%	3.37%	3.38%	8.36%	8.79%	9.45%
American Electric Power Company, Inc.	AEP	68.11	2.24	3.29%	3.77%	4.32%	4.69%	3.35%	3.36%	3.37%	7.12%	7.68%	8.06%
Alliant Energy Corporation	LNT	39.38	1.17	2.97%	6.00%	6.22%	6.60%	3.06%	3.06%	3.07%	9.06%	9.29%	9.67%
Avista Corporation	AVA	43.03	1.37	3.18%	5.00%	5.00%	5.00%	3.26%	3.26%	3.26%	8.26%	8.26%	8.26%
CMS Energy Corporation	CMS	44.28	1.25	2.82%	6.00%	6.61%	7.24%	2.91%	2.92%	2.93%	8.91%	9.53%	10.17%
DTE Energy	DTE	95.92	2.92	3.04%	4.50%	5.22%	5.80%	3.11%	3.12%	3.13%	7.61%	8.34%	8.93%
Northwestern Corp	NWE	61.25	2.00	3.27%	5.00%	5.50%	6.50%	3.35%	3.36%	3.37%	8.35%	8.86%	9.87%
PNM Resources	PNM	34.39	0.88	2.56%	7.60%	8.45%	9.00%	2.66%	2.67%	2.67%	10.26%	11.12%	11.67%
Scana Corp	SCG	72.88	2.30	3.16%	4.50%	5.06%	5.40%	3.23%	3.24%	3.24%	7.73%	8.29%	8.64%
Xcel Energy Inc	XEL	43.38	1.36	3.14%	5.23%	5.33%	5.50%	3.22%	3.22%	3.22%	8.45%	8.55%	8.72%
Mean				3.10%	5.15%	5.63%	6.12%	3.17%	3.18%	3.19%	8.32%	8.82%	9.31%
Required ROE including flotation cost adjustment											8.45%	8.95%	9.44%
Flotation Costs											3.94%		

Sources and Notes:
[1] REVISED DOC Ex. __ JPK-11, Schedule 16 - d
[2] REVISED DOC Ex. __ JPK-11, Schedule 16 - d
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-11, Schedule 15 - d
[5] REVISED DOC Ex. __ JPK-11, Schedule 15 - d
[6] REVISED DOC Ex. __ JPK-11, Schedule 15 - d
[7] = [3] x (1 + 0.5 x [4])
[8] = [3] x (1 + 0.5 x [5])
[9] = [3] x (1 + 0.5 x [6])
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

UPDATED - Two Growth Rate DCF Analysis - OTP Proxy Group $10 Billion Market Capitalization Criterion Scenario
Mean Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Mean Projected Growth Rate	Mean Expected Dividend Yield	Second Growth Rate		Mean Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
ALE	62.26	2.08	3.34%	4.83%	3.42%	4.83%		8.25%
AEE	51.80	1.70	3.28%	5.42%	3.37%	5.42%		8.79%
AEP	68.11	2.24	3.29%	4.32%	3.36%	4.56%		7.88%
LNT	39.38	1.17	2.97%	6.22%	3.06%	6.22%		9.29%
AVA	43.03	1.37	3.18%	5.00%	3.26%	5.00%		8.26%
CMS	44.28	1.25	2.82%	6.61%	2.92%	6.61%		9.53%
DTE	95.92	2.92	3.04%	5.22%	3.12%	5.22%		8.34%
NWE	61.25	2.00	3.27%	5.50%	3.36%	5.50%		8.86%
PNM	34.39	0.88	2.56%	8.45%	2.67%	6.71%		9.58%
SCG	72.88	2.30	3.16%	5.06%	3.24%	5.06%		8.29%
XEL	43.38	1.36	3.14%	5.33%	3.22%	5.33%		8.55%
Mean			3.10%	5.63%	3.18%	5.50%		8.69%
With Flotation Costs								8.82%
		Average		5.63%				
		Std. Dev.		1.07%			Flotation Costs (F)	3.94%
		Avg. less St. Dev.		4.56%				
		Avg. plus St. Dev		6.71%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ALE	2.13	1.08	1.97	2.23	1.17	1.91	2.34	1.27	1.85	2.45	1.37	1.79	2.57	1.49	1.73	2.70	78.83	53.02	62.26	0.00
AEE	1.75	1.09	1.60	1.84	1.18	1.56	1.94	1.29	1.51	2.05	1.40	1.46	2.16	1.52	1.42	2.27	67.46	44.26	51.80	0.00
AEP	2.29	1.08	2.12	2.39	1.16	2.05	2.49	1.26	1.98	2.60	1.35	1.92	2.71	1.46	1.85	2.83	85.03	58.18	68.11	0.00
LNT	1.21	1.09	1.10	1.28	1.19	1.07	1.36	1.31	1.04	1.45	1.43	1.01	1.54	1.56	0.99	1.63	53.25	34.16	39.38	0.00
AVA	1.40	1.08	1.30	1.47	1.17	1.26	1.55	1.27	1.22	1.63	1.37	1.18	1.71	1.49	1.15	1.79	54.92	36.92	43.03	0.00
CMS	1.29	1.10	1.18	1.38	1.20	1.15	1.47	1.31	1.12	1.56	1.44	1.09	1.67	1.58	1.06	1.78	60.99	38.69	44.28	0.00
DTE	3.00	1.08	2.77	3.15	1.17	2.69	3.32	1.27	2.61	3.49	1.38	2.53	3.67	1.49	2.46	3.86	123.69	82.87	95.92	0.00
NWE	2.06	1.09	1.89	2.17	1.18	1.83	2.29	1.29	1.77	2.41	1.40	1.72	2.55	1.53	1.67	2.69	80.04	52.37	61.24	0.00
PNM	0.92	1.10	0.84	0.99	1.20	0.83	1.08	1.32	0.82	1.17	1.44	0.81	1.27	1.58	0.80	1.38	47.87	30.29	34.39	0.00
SCG	2.36	1.08	2.18	2.48	1.17	2.11	2.60	1.27	2.05	2.73	1.38	1.99	2.87	1.49	1.93	3.02	93.26	62.62	72.88	0.00
XEL	1.40	1.09	1.29	1.47	1.18	1.25	1.55	1.28	1.21	1.63	1.39	1.18	1.72	1.51	1.14	1.81	56.24	37.31	43.38	0.00

Sources and Notes:
[1] REVISED DOC Ex. __ JPK-11, Schedule 16 - d
[2] REVISED DOC Ex. __ JPK-11, Schedule 16 - d
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-11, Schedule 15 - d
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (4.56%), then equal to 4.56%',
if [4] is greater than Group Avg. plu St. Dev. (6.71%), then equal to 6.71%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:
[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

UPDATED - Constant Growth DCF Analysis - OTP Proxy Group - Customer Density < 250 per Square Mile Criterion Scenario

Company	Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
ALLETE, Inc.	ALE	62.26	2.08	3.34%	4.00%	4.83%	5.50%	3.41%	3.42%	3.43%	7.41%	8.25%	8.93%
Ameren Corporation	AEE	51.80	1.70	3.28%	5.00%	5.42%	6.07%	3.36%	3.37%	3.38%	8.36%	8.79%	9.45%
Alliant Energy Corporation	LNT	39.38	1.17	2.97%	6.00%	6.22%	6.60%	3.06%	3.06%	3.07%	9.06%	9.29%	9.67%
Avista Corporation	AVA	43.03	1.37	3.18%	5.00%	5.00%	5.00%	3.26%	3.26%	3.26%	8.26%	8.26%	8.26%
CMS Energy Corporation	CMS	44.28	1.25	2.82%	6.00%	6.61%	7.24%	2.91%	2.92%	2.93%	8.91%	9.53%	10.17%
NorthWestern Corporation	NWE	61.25	2.00	3.27%	5.00%	5.50%	6.50%	3.35%	3.36%	3.37%	8.35%	8.86%	9.87%
Pinnacle West Capital Corp	PNW	78.53	2.50	3.18%	3.73%	3.93%	4.05%	3.24%	3.25%	3.25%	6.97%	7.17%	7.30%
PNM Resources Inc	PNM	34.39	0.88	2.56%	7.60%	8.45%	9.00%	2.66%	2.67%	2.67%	10.26%	11.12%	11.67%
Portland General Electric	POR	43.04	1.28	2.97%	5.50%	6.17%	6.57%	3.06%	3.07%	3.07%	8.56%	9.24%	9.64%
Scana Corp	SCG	72.88	2.30	3.16%	4.50%	5.06%	5.40%	3.23%	3.24%	3.24%	7.73%	8.29%	8.64%
Mean				3.07%	5.23%	5.72%	6.19%	3.15%	3.16%	3.17%	8.39%	8.88%	9.36%
Required ROE including flotation cost adjustment											8.52%	9.01%	9.49%
Flotation Costs											3.94%		

Sources and Notes:
[1] REVISED DOC Ex. __ JPK-11, Schedule 16 - e
[2] REVISED DOC Ex. __ JPK-11, Schedule 16 - e
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-11, Schedule 15 - e
[5] REVISED DOC Ex. __ JPK-11, Schedule 15 - e
[6] REVISED DOC Ex. __ JPK-11, Schedule 15 - e
[7] = [3] x (1 + 0.5 x [4])
[8] = [3] x (1 + 0.5 x [5])
[9] = [3] x (1 + 0.5 x [6])
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

CORRECTED - Two Growth Rate DCF Analysis - OTP Proxy Group Customer Densityy < 250 Customers per Square Mile Criterion Scenario
Mean Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Mean Projected Growth Rate	Mean Expected Dividend Yield	Second Growth Rate		Mean Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
ALE	62.26	2.08	3.34%	4.83%	3.42%	4.83%		8.25%
AEE	51.80	1.70	3.28%	5.42%	3.37%	5.42%		8.79%
LNT	39.38	1.17	2.97%	6.22%	3.06%	6.22%		9.29%
AVA	43.03	1.37	3.18%	5.00%	3.26%	5.00%		8.26%
CMS	44.28	1.25	2.82%	6.61%	2.92%	6.61%		9.53%
NWE	61.25	2.00	3.27%	5.50%	3.36%	5.50%		8.86%
PNW	78.53	2.50	3.18%	3.93%	3.25%	4.54%		7.70%
PNM	34.39	0.88	2.56%	8.45%	2.67%	6.90%		9.75%
POR	43.04	1.28	2.97%	6.17%	3.07%	6.17%		9.24%
SCG	72.88	2.30	3.16%	5.06%	3.24%	5.06%		8.29%
Mean			3.07%	5.72%	3.16%	5.63%		8.80%
With Flotation Costs								8.93%
		Average		5.72%				
		Std. Dev.		1.18%			Flotation Costs (F)	3.94%
		Avg. less St. Dev.		4.54%				
		Avg. plus St. Dev		6.90%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ALE	2.13	1.08	1.97	2.23	1.17	1.91	2.34	1.27	1.85	2.45	1.37	1.79	2.57	1.49	1.73	2.70	78.83	53.02	62.26	0.00
AEE	1.75	1.09	1.60	1.84	1.18	1.56	1.94	1.29	1.51	2.05	1.40	1.46	2.16	1.52	1.42	2.27	67.46	44.26	51.80	0.00
LNT	1.21	1.09	1.10	1.28	1.19	1.07	1.36	1.31	1.04	1.45	1.43	1.01	1.54	1.56	0.99	1.63	53.25	34.16	39.38	0.00
AVA	1.40	1.08	1.30	1.47	1.17	1.26	1.55	1.27	1.22	1.63	1.37	1.18	1.71	1.49	1.15	1.79	54.92	36.92	43.03	0.00
CMS	1.29	1.10	1.18	1.38	1.20	1.15	1.47	1.31	1.12	1.56	1.44	1.09	1.67	1.58	1.06	1.78	60.99	38.69	44.28	0.00
NWE	2.06	1.09	1.89	2.17	1.18	1.83	2.29	1.29	1.77	2.41	1.40	1.72	2.55	1.53	1.67	2.69	80.05	52.37	61.25	0.00
PNW	2.55	1.08	2.37	2.65	1.16	2.28	2.75	1.25	2.20	2.86	1.35	2.13	2.97	1.45	2.05	3.09	97.83	67.50	78.53	0.00
PNM	0.92	1.10	0.84	0.99	1.20	0.83	1.08	1.32	0.82	1.17	1.45	0.81	1.27	1.59	0.80	1.38	48.26	30.31	34.39	0.00
POR	1.32	1.09	1.21	1.40	1.19	1.17	1.49	1.30	1.14	1.58	1.42	1.11	1.68	1.56	1.08	1.78	58.06	37.33	43.04	0.00
SCG	2.36	1.08	2.18	2.48	1.17	2.11	2.60	1.27	2.05	2.73	1.38	1.99	2.87	1.49	1.93	3.02	93.26	62.62	72.88	0.00

Sources and Notes:
[1] REVISED DOC Ex. __ JPK-11, Schedule 16 - e
[2] REVISED DOC Ex. __ JPK-11, Schedule 16 - e
[3] = [2] / [1]
[4] REVISED DOC Ex. __ JPK-11, Schedule 15 - e
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (4.54%), then equal to 4.54%',
if [4] is greater than Group Avg. plu St. Dev. (6.90%), then equal to 6.90%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:
[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

CORRECTED - Constant Growth DCF Analysis - OTP Proxy Group - Party to a Merger of Other Significant Transaction Criterion Scenario

Company	Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
ALLETE, Inc.	ALE	62.26	2.08	3.34%	4.00%	4.83%	5.50%	3.41%	3.42%	3.43%	7.41%	8.25%	8.93%
Ameren Corporation	AEE	51.80	1.70	3.28%	5.00%	5.42%	6.07%	3.36%	3.37%	3.38%	8.36%	8.79%	9.45%
Alliant Energy Corporation	LNT	39.38	1.17	2.97%	6.00%	6.22%	6.60%	3.06%	3.06%	3.07%	9.06%	9.29%	9.67%
Avista Corporation	AVA	43.03	1.37	3.18%	5.00%	5.00%	5.00%	3.26%	3.26%	3.26%	8.26%	8.26%	8.26%
CMS Energy Corporation	CMS	44.28	1.25	2.82%	6.00%	6.61%	7.24%	2.91%	2.92%	2.93%	8.91%	9.53%	10.17%
Edison International	EIX	75.34	1.92	2.55%	2.55%	3.80%	5.34%	2.58%	2.60%	2.62%	5.13%	6.39%	7.96%
Entergy Corp	ETR	79.39	3.40	4.28%	-2.25%	-0.37%	3.00%	4.23%	4.27%	4.35%	1.98%	3.91%	7.35%
NorthWestern Corporation	NWE	61.25	2.00	3.27%	5.00%	5.50%	6.50%	3.35%	3.36%	3.37%	8.35%	8.86%	9.87%
PG&E Corp	PCG	63.20	1.96	3.10%	5.07%	7.70%	12.00%	3.18%	3.22%	3.29%	8.25%	10.92%	15.29%
PNM Resources Inc	PNM	34.39	0.88	2.56%	7.60%	8.45%	9.00%	2.66%	2.67%	2.67%	10.26%	11.12%	11.67%
Scana Corp	SCG	72.88	2.30	3.16%	4.50%	5.06%	5.40%	3.23%	3.24%	3.24%	7.73%	8.29%	8.64%
Mean				3.14%	4.41%	5.29%	6.51%	3.20%	3.22%	3.24%	7.61%	8.51%	9.75%
Required ROE including flotation cost adjustment											7.74%	8.64%	9.88%
Flotation Costs											3.94%		

Sources and Notes:
[1] DOC Ex. __ JPK-11, Schedule 16 - f
[2] DOC Ex. __ JPK-11, Schedule 16 - f
[3] = [2] / [1]
[4] DOC Ex. __ JPK-11, Schedule 15 - f
[5] DOC Ex. __ JPK-11, Schedule 15 - f
[6] DOC Ex. __ JPK-11, Schedule 15 - f
[7] = [3] x (1 + 0.5 x [4])
[8] = [3] x (1 + 0.5 x [5])
[9] = [3] x (1 + 0.5 x [6])
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

UPDATED - Two Growth Rate DCF Analysis - OTP Proxy Group Party to a Merger or Other Significant Transaction Criterion Scenario
Mean Growth Rates

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Mean Projected Growth Rate	Mean Expected Dividend Yield	Second Growth Rate		Mean Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
ALE	62.26	2.08	3.34%	4.83%	3.42%	4.83%		8.25%
AEE	51.80	1.70	3.28%	5.42%	3.37%	5.42%		8.79%
LNT	39.38	1.17	2.97%	6.22%	3.06%	6.22%		9.29%
AVA	43.03	1.37	3.18%	5.00%	3.26%	5.00%		8.26%
CMS	44.28	1.25	2.82%	6.61%	2.92%	6.61%		9.53%
EIX	75.34	1.92	2.55%	3.80%	2.60%	3.80%		6.39%
ETR	79.39	3.40	4.28%	-0.37%	4.27%	3.10%		6.77%
NWE	61.25	2.00	3.27%	5.50%	3.36%	5.50%		8.86%
PCG	63.20	1.96	3.10%	7.70%	3.22%	7.49%		10.74%
PNM	34.39	0.88	2.56%	8.45%	2.67%	7.49%		10.27%
SCG	72.88	2.30	3.16%	5.06%	3.24%	5.06%		8.29%
Mean			3.14%	5.29%	3.22%	5.50%		8.68%
With Flotation Costs								8.81%
		Average		5.29%				
		Std. Dev.		2.20%			Flotation Costs (F)	3.94%
		Avg. less St. Dev.		3.10%				
		Avg. plus St. Dev		7.49%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ALE	2.13	1.08	1.97	2.23	1.17	1.91	2.34	1.27	1.85	2.45	1.37	1.79	2.57	1.49	1.73	2.70	78.83	53.02	62.26	0.00
AEE	1.75	1.09	1.60	1.84	1.18	1.56	1.94	1.29	1.51	2.05	1.40	1.46	2.16	1.52	1.42	2.27	67.46	44.26	51.80	0.00
LNT	1.21	1.09	1.10	1.28	1.19	1.07	1.36	1.31	1.04	1.45	1.43	1.01	1.54	1.56	0.99	1.63	53.25	34.16	39.38	0.00
AVA	1.40	1.08	1.30	1.47	1.17	1.26	1.55	1.27	1.22	1.63	1.37	1.18	1.71	1.49	1.15	1.79	54.92	36.92	43.03	0.00
CMS	1.29	1.10	1.18	1.38	1.20	1.15	1.47	1.31	1.12	1.56	1.44	1.09	1.67	1.58	1.06	1.78	60.99	38.69	44.28	0.00
EIX	1.96	1.06	1.84	2.03	1.13	1.79	2.11	1.20	1.75	2.19	1.28	1.71	2.27	1.36	1.67	2.36	90.77	66.59	75.34	0.00
ETR	3.39	1.07	3.18	3.38	1.14	2.97	3.37	1.22	2.77	3.36	1.30	2.58	3.34	1.39	2.41	3.33	90.84	65.48	79.39	0.00
NWE	2.06	1.09	1.89	2.17	1.18	1.83	2.29	1.29	1.77	2.41	1.40	1.72	2.55	1.53	1.67	2.69	80.05	52.37	61.25	0.00
PCG	2.04	1.11	1.84	2.19	1.23	1.79	2.36	1.36	1.74	2.54	1.50	1.69	2.74	1.67	1.64	2.95	90.77	54.50	63.20	0.00
PNM	0.92	1.10	0.83	0.99	1.22	0.82	1.08	1.34	0.80	1.17	1.48	0.79	1.27	1.63	0.78	1.38	49.51	30.37	34.39	0.00
SCG	2.36	1.08	2.18	2.48	1.17	2.11	2.60	1.27	2.05	2.73	1.38	1.99	2.87	1.49	1.93	3.02	93.26	62.62	72.88	0.00

Sources and Notes:

[1] DOC Ex. __ JPK-11, Schedule 16 - f
[2] DOC Ex. __ JPK-11, Schedule 16 - f
[3] = [2] / [1]
[4] DOC Ex. __ JPK-11, Schedule 15 - f
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (3.10%), then equal to 3.10%',
if [4] is greater than Group Avg. plu St. Dev. (7.49%), then equal to 7.49%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

UPDATED - Constant Growth DCF Analysis - OTP Proxy Group - 8.00 Percent Minimum ROE Criterion Scenario

Company	Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate	Low Expected Dividend Yield	Mean Expected Dividend Yield	High Expected Dividend Yield	Low ROE	Mean ROE	High ROE
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
ALLETE, Inc.	ALE	62.26	2.08	3.34%	4.00%	4.83%	5.50%	3.41%	3.42%	3.43%	7.41%	8.25%	8.93%
Ameren Corporation	AEE	51.80	1.70	3.28%	5.00%	5.42%	6.07%	3.36%	3.37%	3.38%	8.36%	8.79%	9.45%
Alliant Energy Corporation	LNT	39.38	1.17	2.97%	6.00%	6.22%	6.60%	3.06%	3.06%	3.07%	9.06%	9.29%	9.67%
Avista Corporation	AVA	43.03	1.37	3.18%	5.00%	5.00%	5.00%	3.26%	3.26%	3.26%	8.26%	8.26%	8.26%
CMS Energy Corporation	CMS	44.28	1.25	2.82%	6.00%	6.61%	7.24%	2.91%	2.92%	2.93%	8.91%	9.53%	10.17%
IdaCorp	IDA	77.51	2.04	2.63%	3.00%	3.67%	4.00%	2.67%	2.68%	2.68%	5.67%	6.35%	6.68%
NorthWestern Corporation	NWE	61.25	2.00	3.27%	5.00%	5.50%	6.50%	3.35%	3.36%	3.37%	8.35%	8.86%	9.87%
OGE Energy	OGE	31.56	1.10	3.49%	2.50%	3.88%	5.15%	3.53%	3.55%	3.58%	6.03%	7.44%	8.73%
PNM Resources Inc	PNM	34.39	0.88	2.56%	7.60%	8.45%	9.00%	2.66%	2.67%	2.67%	10.26%	11.12%	11.67%
Scana Corp	SCG	72.88	2.30	3.16%	4.50%	5.06%	5.40%	3.23%	3.24%	3.24%	7.73%	8.29%	8.64%
Mean				3.07%	4.86%	5.47%	6.05%	3.14%	3.15%	3.16%	8.00%	8.62%	9.21%
Required ROE including flotation cost adjustment											8.13%	8.75%	9.34%
Flotation Costs											3.94%		

Sources and Notes:
[1] DOC Ex. __ JPK-11, Schedule 16 - g
[2] DOC Ex. __ JPK-11, Schedule 16 - g
[3] = [2] / [1]
[4] DOC Ex. __ JPK-11, Schedule 15 - g
[5] DOC Ex. __ JPK-11, Schedule 15 - g
[6] DOC Ex. __ JPK-11, Schedule 15 - g
[7] = [3] x (1 + 0.5 x [4])
[8] = [3] x (1 + 0.5 x [5])
[9] = [3] x (1 + 0.5 x [6])
[10] = [4] + [7]
[11] = [5] + [8]
[12] = [6] + [9]

CORRECTED - Two Growth Rate DCF Analysis - OTP Proxy Group 8.00 Percent Minimum ROE Criterion Scenario
Mean Growth Rates

Docket No. E017/GR-15-1033
REVISED DOC Ex. __ JPK-11, CORRECTED - Schedule 14

Ticker	Average Closing Price	Annualized Dividend	Dividend Yield	Mean Projected Growth Rate	Mean Expected Dividend Yield	Second Growth Rate		Mean Expected ROE
	[1]	[2]	[3]	[4]	[5]	[6]		[7]
ALE	62.26	2.08	3.34%	4.83%	3.42%	4.83%		8.25%
AEE	51.80	1.70	3.28%	5.42%	3.37%	5.42%		8.79%
LNT	39.38	1.17	2.97%	6.22%	3.06%	6.22%		9.29%
AVA	43.03	1.37	3.18%	5.00%	3.26%	5.00%		8.26%
CMS	44.28	1.25	2.82%	6.61%	2.92%	6.61%		9.53%
IDA	77.51	2.04	2.63%	3.67%	2.68%	4.15%		6.77%
NWE	61.25	2.00	3.27%	5.50%	3.36%	5.50%		8.86%
OGE	31.56	1.10	3.49%	3.88%	3.55%	4.15%		7.66%
PNM	34.39	0.88	2.56%	8.45%	2.67%	6.78%		9.65%
SCG	72.88	2.30	3.16%	5.06%	3.24%	5.06%		8.29%
Mean			3.07%	5.47%	3.15%	5.37%		8.54%
With Flotation Costs								8.67%
		Average		5.47%				
		Std. Dev.		1.32%			Flotation Costs (F)	3.94%
		Avg. less St. Dev.		4.15%				
		Avg. plus St. Dev		6.78%				

Ticker	Year 1 Div.	(1+k)^1	PV of Year 1 Div.	Year 2 Div.	(1+k)^2	PV of Year 2 Div.	Year 3 Div.	(1+k)^3	PV of Year 3 Div.	Year 4 Div.	(1+k)^4	PV of Year 4 Div.	Year 5 Div.	(1+k)^5	PV of Year 5 Div.	Year 6 Div.	Year 5 Stock Price	PV of Year 5 Stock Price	Current Stock Price	CHECK
	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]	[26]	[27]
ALE	2.13	1.08	1.97	2.23	1.17	1.91	2.34	1.27	1.85	2.45	1.37	1.79	2.57	1.49	1.73	2.70	78.83	53.02	62.26	0.00
AEE	1.75	1.09	1.60	1.84	1.18	1.56	1.94	1.29	1.51	2.05	1.40	1.46	2.16	1.52	1.42	2.27	67.46	44.26	51.80	0.00
LNT	1.21	1.09	1.10	1.28	1.19	1.07	1.36	1.31	1.04	1.45	1.43	1.01	1.54	1.56	0.99	1.63	53.25	34.16	39.38	0.00
AVA	1.40	1.08	1.30	1.47	1.17	1.26	1.55	1.27	1.22	1.63	1.37	1.18	1.71	1.49	1.15	1.79	54.92	36.92	43.03	0.00
CMS	1.29	1.10	1.18	1.38	1.20	1.15	1.47	1.31	1.12	1.56	1.44	1.09	1.67	1.58	1.06	1.78	60.99	38.69	44.28	0.00
IDA	2.08	1.07	1.95	2.15	1.14	1.89	2.23	1.22	1.83	2.31	1.30	1.78	2.40	1.39	1.73	2.49	94.81	68.33	77.51	0.00
NWE	2.06	1.09	1.89	2.17	1.18	1.83	2.29	1.29	1.77	2.41	1.40	1.72	2.55	1.53	1.67	2.69	80.05	52.37	61.25	0.00
OGE	1.12	1.08	1.04	1.16	1.16	1.01	1.21	1.25	0.97	1.26	1.34	0.94	1.31	1.45	0.90	1.36	38.63	26.71	31.56	0.00
PNM	0.92	1.10	0.84	0.99	1.20	0.83	1.08	1.32	0.82	1.17	1.45	0.81	1.27	1.58	0.80	1.38	48.02	30.30	34.39	0.00
SCG	2.36	1.08	2.18	2.48	1.17	2.11	2.60	1.27	2.05	2.73	1.38	1.99	2.87	1.49	1.93	3.02	93.26	62.62	72.88	0.00

Sources and Notes:

[1] DOC Ex. __ JPK-11, Schedule 16 - g
[2] DOC Ex. __ JPK-11, Schedule 16 - g
[3] = [2] / [1]
[4] DOC Ex. __ JPK-11, Schedule 15 - g
[5] = [3] x (1 + 0.5 x [4])
[6] if [4] is less than Group Avg. less St. Dev. (4.15%), then equal to 4.15%',
if [4] is greater than Group Avg. plu St. Dev. (6.78%), then equal to 6.78%
else equal to [4]
[7] ROE that sets [1] equal to [26]; solved using Excel's Goal Seek function
Adjustment for Flotation costs: ROE = [7] - [5] + [5]/(1-F)
[8] = [1] x [5]
[9] = (1 + [7])^1
[10] = [8] / [9]
[11] = [8] x (1 + [4])
[12] = (1 + [7])^2
[13] = [11] / [12]
(continued)

Sources and Notes, Continued:

[14] = [11] x (1 + [4])
[15] = (1 + [7])^3
[16] = [14] / [15]
[17] = [14] x (1 + [4])
[18] = (1 + [7])^4
[19] = [17] / [18]
[20] = [17] x (1 + [4])
[21] = (1 + [7])^5
[22] = [20] / [21]
[23] = [20] x (1 + [6])
[24] = [23] / ([7] - [6])
[25] = [24] / [21]
[26] = [10] + [13] + [16] + [19] + [22] + [25]
[27] = [26] - [1]

Projected Growth Rates
DOC Electric Proxy Group

Company	Ticker	Zacks	Thomson	Value Line	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate
		[1]	[2]	[3]	[4]	[5]	[6]
ALLETE, Inc.	ALE	5.50%	5.00%	4.00%	4.00%	4.83%	5.50%
Ameren Corporation	AEE	6.07%	5.20%	5.00%	5.00%	5.42%	6.07%
Alliant Energy Corporation	LNT	6.07%	6.60%	6.00%	6.00%	6.22%	6.60%
Avista Corporation	AVA	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
CMS Energy Corporation	CMS	6.60%	7.24%	6.00%	6.00%	6.61%	7.24%
NorthWestern Corporation	NWE	5.00%	5.00%	6.50%	5.00%	5.50%	6.50%
PNM Resources, Inc.	PNM	7.60%	8.76%	9.00%	7.60%	8.45%	9.00%
SCANA Corporation	SCG	5.27%	5.40%	4.50%	4.50%	5.06%	5.40%
Average		5.89%	6.03%	5.75%	5.39%	5.89%	6.41%

Sources and notes:
[1] Zacks Investment Research
[2] Thomson Financial Network; Accessed via Yahoo! Finance
[3] Value Line
[4] = min([1], [2], [3])
[5] = average([1], [2], [3])
[6] = max([1], [2], [3])

Projected Growth Rates
OTP Proxy Group - Consistently Pays Quarterly Dividends Scenario

Company	Ticker	Zacks	Thomson	Value Line	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate
		[1]	[2]	[3]	[4]	[5]	[6]
ALLETE, Inc.	ALE	5.50%	5.00%	4.00%	4.00%	4.83%	5.50%
Ameren Corporation	AEE	6.07%	5.20%	5.00%	5.00%	5.42%	6.07%
Alliant Energy Corporation	LNT	6.07%	6.60%	6.00%	6.00%	6.22%	6.60%
Avista Corporation	AVA	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
CMS Energy Corporation	CMS	6.60%	7.24%	6.00%	6.00%	6.61%	7.24%
El Paso Electric Company	EE	6.70%	n/a	2.50%	2.50%	4.60%	6.70%
NorthWestern Corporation	NWE	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
PNM Resources, Inc.	PNM	7.60%	8.76%	9.00%	7.60%	8.45%	9.00%
Scana Corp	SCG	5.27%	5.40%	4.50%	4.50%	5.06%	5.40%
Average		5.98%	6.03%	5.22%	5.07%	5.69%	6.28%

Sources and notes:
[1] Zacks Investment Research
[2] Thomson Financial Network; Accessed via Yahoo! Finance
[3] Value Line
[4] = min([1], [2], [3])
[5] = average([1], [2], [3])
[6] = max([1], [2], [3])

Projected Growth Rates
OTP Electric Proxy Group - Symmetrical Credit Rating Scenario

Company	Ticker	Zacks	Thomson	Value Line	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate
		[1]	[2]	[3]	[4]	[5]	[6]
ALLETE, Inc.	ALE	5.50%	5.00%	4.00%	4.00%	4.83%	5.50%
Ameren Corporation	AEE	6.07%	5.20%	5.00%	5.00%	5.42%	6.07%
Avista Corporation	AVA	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
CMS Energy Corporation	CMS	6.60%	7.24%	6.00%	6.00%	6.61%	7.24%
NorthWestern Corporation	NWE	5.00%	5.00%	6.50%	5.00%	5.50%	6.50%
PNM Resources, Inc.	PNM	7.60%	8.76%	9.00%	7.60%	8.45%	9.00%
SCANA Corporation	SCG	5.27%	5.40%	4.50%	4.50%	5.06%	5.40%
	#N/A						
Average		5.86%	5.94%	5.71%	5.30%	5.84%	6.39%

Sources and notes:
[1] Zacks Investment Research
[2] Thomson Financial Network; Accessed via Yahoo! Finance
[3] Value Line
[4] = min([1], [2], [3])
[5] = average([1], [2], [3])
[6] = max([1], [2], [3])

Projected Growth Rates
OTP Proxy Group - $10 Billion Market Cap Scenario

Company	Ticker	Zacks	Thomson	Value Line	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate
		[1]	[2]	[3]	[4]	[5]	[6]
ALLETE, Inc.	ALE	5.50%	5.00%	4.00%	4.00%	4.83%	5.50%
Ameren Corporation	AEE	6.07%	5.20%	5.00%	5.00%	5.42%	6.07%
American Electric Power Company, Inc.	AEP	4.69%	3.77%	4.50%	3.77%	4.32%	4.69%
Alliant Energy Corporation	LNT	6.07%	6.60%	6.00%	6.00%	6.22%	6.60%
Avista Corporation	AVA	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
CMS Energy Corporation	CMS	6.60%	7.24%	6.00%	6.00%	6.61%	7.24%
DTE Energy Company	DTE	5.80%	5.35%	4.50%	4.50%	5.22%	5.80%
NorthWestern Corporation	NWE	5.00%	5.00%	6.50%	5.00%	5.50%	6.50%
PNM Resources Inc.	PNM	7.60%	8.76%	9.00%	7.60%	8.45%	9.00%
Scana Corp	SCG	5.27%	5.40%	4.50%	4.50%	5.06%	5.40%
XEL Energy Co	XEL	5.23%	5.27%	5.50%	5.23%	5.33%	5.50%
Average		5.71%	5.69%	5.50%	5.15%	5.63%	6.12%

Sources and notes:

[1] Zacks Investment Research
[2] Thomson Financial Network; Accessed via Yahoo! Finance
[3] Value Line
[4] = min([1], [2], [3])
[5] = average([1], [2], [3])
[6] = max([1], [2], [3])

Projected Growth Rates
OTP Proxy Group less than 250 Customers per Square Mile Scenario

Company	Ticker	Zacks	Thomson	Value Line	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate
		[1]	[2]	[3]	[4]	[5]	[6]
ALLETE, Inc.	ALE	5.50%	5.00%	4.00%	4.00%	4.83%	5.50%
Ameren Corporation	AEE	6.07%	5.20%	5.00%	5.00%	5.42%	6.07%
Alliant Energy Corporation	LNT	6.07%	6.60%	6.00%	6.00%	6.22%	6.60%
Avista Corporation	AVA	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
CMS Energy Corporation	CMS	6.60%	7.24%	6.00%	6.00%	6.61%	7.24%
NorthWestern Corporation	NWE	5.00%	5.00%	6.50%	5.00%	5.50%	6.50%
Pinnacle West Capital Corporation	PNW	4.05%	3.73%	4.00%	3.73%	3.93%	4.05%
PNM Resources, Inc.	PNM	7.60%	8.76%	9.00%	7.60%	8.45%	9.00%
Portland General Electric	POR	6.45%	6.57%	5.50%	5.50%	6.17%	6.57%
Scana Corp	SCG	5.27%	5.40%	4.50%	4.50%	5.06%	5.40%
Average		5.76%	5.85%	5.55%	5.23%	5.72%	6.19%

Sources and notes:
[1] Zacks Investment Research
[2] Thomson Financial Network; Accessed via Yahoo! Finance
[3] Value Line
[4] = min([1], [2], [3])
[5] = average([1], [2], [3])
[6] = max([1], [2], [3])

Projected Growth Rates
OTP Proxy Group - Party to a Merger or Other Significant Transaction Scenario

Company	Ticker	Zacks	Thomson	Value Line	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate
		[1]	[2]	[3]	[4]	[5]	[6]
ALLETE, Inc.	ALE	5.50%	5.00%	4.00%	4.00%	4.83%	5.50%
Ameren Corporation	AEE	6.07%	5.20%	5.00%	5.00%	5.42%	6.07%
Alliant Energy Corporation	LNT	6.07%	6.60%	6.00%	6.00%	6.22%	6.60%
Avista Corporation	AVA	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
CMS Energy Corporation	CMS	6.60%	7.24%	6.00%	6.00%	6.61%	7.24%
Edison International	EIX	5.34%	2.55%	3.50%	2.55%	3.80%	5.34%
Entergy Corporation	ETR	-2.25%	-1.85%	3.00%	-2.25%	-0.37%	3.00%
NorthWestern Corporation	NWE	5.00%	5.00%	6.50%	5.00%	5.50%	6.50%
PNM Resources Inc	PNM	7.60%	8.76%	9.00%	7.60%	8.45%	9.00%
Pacific Gas & Electric Corp	PCG	5.07%	6.04%	12.00%	5.07%	7.70%	12.00%
Scana Corp	SCG	5.27%	5.40%	4.50%	4.50%	5.06%	5.40%
Average		5.02%	4.99%	5.86%	4.41%	5.29%	6.51%

Sources and notes:

[1] Zacks Investment Research
[2] Thomson Financial Network; Accessed via Yahoo! Finance
[3] Value Line
[4] = min([1], [2], [3])
[5] = average([1], [2], [3])
[6] = max([1], [2], [3])

Projected Growth Rates
OTP Proxy Group - 8.00 Percent Minimum ROE Scenario

Company	Ticker	Zacks	Thomson	Value Line	Low Projected Growth Rate	Mean Projected Growth Rate	High Projected Growth Rate
		[1]	[2]	[3]	[4]	[5]	[6]
ALLETE, Inc.	ALE	5.50%	5.00%	4.00%	4.00%	4.83%	5.50%
Ameren Corporation	AEE	6.07%	5.20%	5.00%	5.00%	5.42%	6.07%
Alliant Energy Corporation	LNT	6.07%	6.60%	6.00%	6.00%	6.22%	6.60%
Avista Corporation	AVA	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
CMS Energy Corporation	CMS	6.60%	7.24%	6.00%	6.00%	6.61%	7.24%
IDACORP, Inc.	IDA	4.00%	4.00%	3.00%	3.00%	3.67%	4.00%
NorthWestern Corporation	NWE	5.00%	5.00%	6.50%	5.00%	5.50%	6.50%
OGE Energy Corporation	OGE	5.15%	4.00%	2.50%	2.50%	3.88%	5.15%
PNM Resources Inc	PNM	7.60%	8.76%	9.00%	7.60%	8.45%	9.00%
Scana Corp	SCG	5.27%	5.40%	4.50%	4.50%	5.06%	5.40%
Average		5.63%	5.62%	5.15%	4.86%	5.47%	6.05%

Sources and notes:
[1] Zacks Investment Research
[2] Thomson Financial Network; Accessed via Yahoo! Finance
[3] Value Line
[4] = min([1], [2], [3])
[5] = average([1], [2], [3])
[6] = max([1], [2], [3])

30-Day Average Closing Prices and Current Dividends
OTP Electric Proxy Group

	ALE	AEE	LNT	AVA	CMS	NWE	PNM	SCG
Annualized Dividend	2.080	1.700	1.170	1.370	1.250	2.000	0.880	2.300
30 Day Average Closing Stock Price	62.26	51.80	39.38	43.03	44.28	61.25	34.39	72.88
Daily Closing Prices								
7/15/2016	63.74	52.51	39.41	43.44	44.82	61.23	34.26	73.49
7/14/2016	63.48	52.24	39.34	43.35	44.76	61.07	34.13	73.67
7/13/2016	64.29	52.88	39.71	44.00	45.03	61.52	34.70	74.25
7/12/2016	63.67	52.46	39.34	43.53	44.58	61.12	34.53	73.54
7/11/2016	64.36	52.94	40.46	44.23	45.38	62.24	35.10	74.87
7/8/2016	64.30	53.15	40.55	44.18	45.51	61.68	35.28	75.08
7/7/2016	63.68	52.65	39.85	43.85	45.26	61.23	35.17	74.23
7/6/2016	64.91	53.77	40.78	44.97	46.17	63.03	36.05	76.12
7/5/2016	65.16	53.76	40.87	44.87	46.08	63.33	35.90	76.04
7/1/2016	64.58	53.75	40.39	44.49	45.63	62.80	35.24	75.63
6/30/2016	64.63	53.58	39.70	44.80	45.86	63.07	35.44	75.66
6/29/2016	63.05	52.50	39.82	43.28	44.84	62.10	34.41	73.96
6/28/2016	62.52	52.28	39.81	43.22	44.98	61.93	34.22	73.94
6/27/2016	62.01	52.31	39.85	43.18	44.94	61.98	34.18	73.39
6/24/2016	61.79	51.79	39.28	42.56	44.36	61.40	33.73	72.24
6/23/2016	61.78	51.50	38.80	42.19	43.59	60.93	33.63	71.35
6/22/2016	61.09	51.26	38.64	42.02	43.65	60.70	33.36	71.48
6/21/2016	61.72	51.37	39.05	42.33	43.71	61.39	33.70	71.52
6/20/2016	61.79	51.35	38.89	42.38	43.56	61.07	33.62	71.36
6/17/2016	61.09	51.27	38.91	42.45	43.82	61.28	33.67	71.42
6/16/2016	61.07	51.20	38.82	42.55	43.71	61.08	33.91	71.44
6/15/2016	60.54	50.91	38.68	42.24	43.42	60.60	33.99	71.02
6/14/2016	61.41	51.31	39.11	42.76	43.84	61.02	34.43	72.25
6/13/2016	60.76	50.76	38.82	42.46	43.31	60.49	34.29	71.43
6/10/2016	60.81	50.96	38.99	42.46	43.31	60.65	34.44	71.58
6/9/2016	60.99	50.89	39.42	42.42	43.39	60.58	34.57	71.67
6/8/2016	60.41	49.68	38.88	41.91	42.83	59.84	34.27	70.80
6/7/2016	59.82	49.48	38.52	41.51	42.58	59.23	33.79	70.75
6/6/2016	59.36	49.54	38.28	41.55	42.63	59.41	33.85	70.99
6/3/2016	59.02	50.00	38.31	41.69	42.82	59.35	33.85	71.15

Source: Yahoo! Finance

Docket No. E017/GR-15-1033
REVISED DOC Ex. __ JPK-11, Schedule 16 - b

30-Day Average Closing Prices and Current Dividends
OTP Proxy Group - Consistently Pays Quarterly Dividends Scenario

	ALE	AEE	LNT	AVA	CMS	EE	NWE	PNM	SCG
Annualized Dividend	2.080	1.700	1.170	1.370	1.250	1.240	2.000	0.880	2.300
30 Day Average Closing Stock Price	62.26	51.80	39.38	43.03	44.28	46.39	61.25	34.39	72.88
Daily Closing Prices									
7/15/2016	63.74	52.51	39.41	43.44	44.82	47.52	61.23	34.26	73.49
7/14/2016	63.48	52.24	39.34	43.35	44.76	47.51	61.07	34.13	73.67
7/13/2016	64.29	52.88	39.71	44.00	45.03	46.83	61.52	34.70	74.25
7/12/2016	63.67	52.46	39.34	43.53	44.58	46.26	61.12	34.53	73.54
7/11/2016	64.36	52.94	40.46	44.23	45.38	46.70	62.24	35.10	74.87
7/8/2016	64.30	53.15	40.55	44.18	45.51	46.70	61.68	35.28	75.08
7/7/2016	63.68	52.65	39.85	43.85	45.26	46.46	61.23	35.17	74.23
7/6/2016	64.91	53.77	40.78	44.97	46.17	47.55	63.03	36.05	76.12
7/5/2016	65.16	53.76	40.87	44.87	46.08	47.95	63.33	35.90	76.04
7/1/2016	64.58	53.75	40.39	44.49	45.63	47.54	62.80	35.24	75.63
6/30/2016	64.63	53.58	39.70	44.80	45.86	47.27	63.07	35.44	75.66
6/29/2016	63.05	52.50	39.82	43.28	44.84	46.31	62.10	34.41	73.96
6/28/2016	62.52	52.28	39.81	43.22	44.98	46.38	61.93	34.22	73.94
6/27/2016	62.01	52.31	39.85	43.18	44.94	46.26	61.98	34.18	73.39
6/24/2016	61.79	51.79	39.28	42.56	44.36	45.80	61.40	33.73	72.24
6/23/2016	61.78	51.50	38.80	42.19	43.59	45.73	60.93	33.63	71.35
6/22/2016	61.09	51.26	38.64	42.02	43.65	45.20	60.70	33.36	71.48
6/21/2016	61.72	51.37	39.05	42.33	43.71	45.52	61.39	33.70	71.52
6/20/2016	61.79	51.35	38.89	42.38	43.56	45.61	61.07	33.62	71.36
6/17/2016	61.09	51.27	38.91	42.45	43.82	45.71	61.28	33.67	71.42
6/16/2016	61.07	51.20	38.82	42.55	43.71	45.64	61.08	33.91	71.44
6/15/2016	60.54	50.91	38.68	42.24	43.42	45.66	60.60	33.99	71.02
6/14/2016	61.41	51.31	39.11	42.76	43.84	46.31	61.02	34.43	72.25
6/13/2016	60.76	50.76	38.82	42.46	43.31	46.01	60.49	34.29	71.43
6/10/2016	60.81	50.96	38.99	42.46	43.31	46.30	60.65	34.44	71.58
6/9/2016	60.99	50.89	39.42	42.42	43.39	46.76	60.58	34.57	71.67
6/8/2016	60.41	49.68	38.88	41.91	42.83	46.45	59.84	34.27	70.80
6/7/2016	59.82	49.48	38.52	41.51	42.58	46.08	59.23	33.79	70.75
6/6/2016	59.36	49.54	38.28	41.55	42.63	45.82	59.41	33.85	70.99
6/3/2016	59.02	50.00	38.31	41.69	42.82	45.80	59.35	33.85	71.15

Source: Yahoo! Finance

Docket No. E017/GR-15-1033
REVISED DOC Ex. __ JPK-11, Schedule 16 - c

30-Day Average Closing Prices and Current Dividends
OTP Electric Proxy Group - Symmetrical Credit Rating Scenario

	ALE	AEE	AVA	CMS	NWE	PNM	SCG
Annualized Dividend	2.080	1.700	1.370	1.250	2.000	0.880	2.300
30 Day Average Closing Stock Price	62.26	51.80	43.03	44.28	61.25	34.39	72.88
Daily Closing Prices							
7/15/2016	63.74	52.51	43.44	44.82	61.23	34.26	73.49
7/14/2016	63.48	52.24	43.35	44.76	61.07	34.13	73.67
7/13/2016	64.29	52.88	44.00	45.03	61.52	34.70	74.25
7/12/2016	63.67	52.46	43.53	44.58	61.12	34.53	73.54
7/11/2016	64.36	52.94	44.23	45.38	62.24	35.10	74.87
7/8/2016	64.30	53.15	44.18	45.51	61.68	35.28	75.08
7/7/2016	63.68	52.65	43.85	45.26	61.23	35.17	74.23
7/6/2016	64.91	53.77	44.97	46.17	63.03	36.05	76.12
7/5/2016	65.16	53.76	44.87	46.08	63.33	35.90	76.04
7/1/2016	64.58	53.75	44.49	45.63	62.80	35.24	75.63
6/30/2016	64.63	53.58	44.80	45.86	63.07	35.44	75.66
6/29/2016	63.05	52.50	43.28	44.84	62.10	34.41	73.96
6/28/2016	62.52	52.28	43.22	44.98	61.93	34.22	73.94
6/27/2016	62.01	52.31	43.18	44.94	61.98	34.18	73.39
6/24/2016	61.79	51.79	42.56	44.36	61.40	33.73	72.24
6/23/2016	61.78	51.50	42.19	43.59	60.93	33.63	71.35
6/22/2016	61.09	51.26	42.02	43.65	60.70	33.36	71.48
6/21/2016	61.72	51.37	42.33	43.71	61.39	33.70	71.52
6/20/2016	61.79	51.35	42.38	43.56	61.07	33.62	71.36
6/17/2016	61.09	51.27	42.45	43.82	61.28	33.67	71.42
6/16/2016	61.07	51.20	42.55	43.71	61.08	33.91	71.44
6/15/2016	60.54	50.91	42.24	43.42	60.60	33.99	71.02
6/14/2016	61.41	51.31	42.76	43.84	61.02	34.43	72.25
6/13/2016	60.76	50.76	42.46	43.31	60.49	34.29	71.43
6/10/2016	60.81	50.96	42.46	43.31	60.65	34.44	71.58
6/9/2016	60.99	50.89	42.42	43.39	60.58	34.57	71.67
6/8/2016	60.41	49.68	41.91	42.83	59.84	34.27	70.80
6/7/2016	59.82	49.48	41.51	42.58	59.23	33.79	70.75
6/6/2016	59.36	49.54	41.55	42.63	59.41	33.85	70.99
6/3/2016	59.02	50.00	41.69	42.82	59.35	33.85	71.15

Source: Yahoo! Finance

Docket No. E017/GR-15-1033
REVISED DOC Ex. __ JPK-11, Schedule 16 - d

30-Day Average Closing Prices and Current Dividends
OTP Proxy Group - $10 Billion Market Cap Scenario

	ALE	AEE	AEP	LNT	AVA	CMS	DTE	NWE	PNM	XEL	SCG
Annualized Dividend	2.080	1.700	2.240	1.170	1.370	1.250	2.920	2.000	0.880	1.360	2.300
30 Day Average Closing Stock Price	62.26	51.80	68.11	39.38	43.03	44.28	95.92	61.25	34.39	43.38	72.88
Daily Closing Prices											
7/15/2016	63.74	52.51	69.64	39.41	43.44	44.82	97.66	61.23	34.26	43.75	73.49
7/14/2016	63.48	52.24	69.38	39.34	43.35	44.76	97.09	61.07	34.13	43.61	73.67
7/13/2016	64.29	52.88	70.01	39.71	44.00	45.03	98.10	61.52	34.70	43.95	74.25
7/12/2016	63.67	52.46	69.58	39.34	43.53	44.58	97.68	61.12	34.53	43.50	73.54
7/11/2016	64.36	52.94	70.70	40.46	44.23	45.38	98.96	62.24	35.10	44.41	74.87
7/8/2016	64.30	53.15	70.71	40.55	44.18	45.51	99.14	61.68	35.28	44.59	75.08
7/7/2016	63.68	52.65	70.28	39.85	43.85	45.26	98.19	61.23	35.17	44.32	74.23
7/6/2016	64.91	53.77	71.27	40.78	44.97	46.17	99.95	63.03	36.05	45.33	76.12
7/5/2016	65.16	53.76	70.81	40.87	44.87	46.08	100.10	63.33	35.90	45.27	76.04
7/1/2016	64.58	53.75	70.14	40.39	44.49	45.63	99.28	62.80	35.24	44.78	75.63
6/30/2016	64.63	53.58	70.09	39.70	44.80	45.86	99.12	63.07	35.44	44.78	75.66
6/29/2016	63.05	52.50	68.72	39.82	43.28	44.84	97.10	62.10	34.41	43.85	73.96
6/28/2016	62.52	52.28	68.64	39.81	43.22	44.98	96.79	61.93	34.22	43.75	73.94
6/27/2016	62.01	52.31	68.35	39.85	43.18	44.94	96.49	61.98	34.18	43.72	73.39
6/24/2016	61.79	51.79	67.26	39.28	42.56	44.36	95.58	61.40	33.73	43.30	72.24
6/23/2016	61.78	51.50	66.59	38.80	42.19	43.59	94.06	60.93	33.63	42.70	71.35
6/22/2016	61.09	51.26	66.50	38.64	42.02	43.65	93.75	60.70	33.36	42.67	71.48
6/21/2016	61.72	51.37	66.77	39.05	42.33	43.71	94.03	61.39	33.70	42.84	71.52
6/20/2016	61.79	51.35	66.79	38.89	42.38	43.56	93.91	61.07	33.62	42.75	71.36
6/17/2016	61.09	51.27	67.21	38.91	42.45	43.82	94.38	61.28	33.67	42.85	71.42
6/16/2016	61.07	51.20	66.88	38.82	42.55	43.71	93.94	61.08	33.91	42.83	71.44
6/15/2016	60.54	50.91	66.24	38.68	42.24	43.42	94.00	60.60	33.99	42.34	71.02
6/14/2016	61.41	51.31	66.83	39.11	42.76	43.84	94.98	61.02	34.43	42.79	72.25
6/13/2016	60.76	50.76	66.55	38.82	42.46	43.31	93.83	60.49	34.29	42.71	71.43
6/10/2016	60.81	50.96	66.85	38.99	42.46	43.31	93.91	60.65	34.44	42.75	71.58
6/9/2016	60.99	50.89	66.96	39.42	42.42	43.39	94.05	60.58	34.57	42.70	71.67
6/8/2016	60.41	49.68	66.20	38.88	41.91	42.83	93.38	59.84	34.27	42.17	70.80
6/7/2016	59.82	49.48	65.84	38.52	41.51	42.58	92.70	59.23	33.79	42.01	70.75
6/6/2016	59.36	49.54	65.70	38.28	41.55	42.63	92.59	59.41	33.85	42.05	70.99
6/3/2016	59.02	50.00	65.81	38.31	41.69	42.82	92.83	59.35	33.85	42.19	71.15

Source: Yahoo! Finance

30-Day Average Closing Prices and Current Dividends
OTP Proxy Group less than 250 Customers per Square Mile Scenario

	ALE	AEE	LNT	AVA	CMS	NWE	PNW	PNM	POR	SCG
Annualized Dividend	2.080	1.700	1.170	1.370	1.250	2.000	2.500	0.880	1.280	2.300
30 Day Average Closing Stock Price	62.26	51.80	39.38	43.03	44.28	61.25	78.53	34.39	43.04	72.88
Daily Closing Prices										
7/15/2016	63.74	52.51	39.41	43.44	44.82	61.23	79.53	34.26	43.80	73.49
7/14/2016	63.48	52.24	39.34	43.35	44.76	61.07	79.35	34.13	43.64	73.67
7/13/2016	64.29	52.88	39.71	44.00	45.03	61.52	80.01	34.70	44.06	74.25
7/12/2016	63.67	52.46	39.34	43.53	44.58	61.12	79.44	34.53	43.51	73.54
7/11/2016	64.36	52.94	40.46	44.23	45.38	62.24	81.08	35.10	44.05	74.87
7/8/2016	64.30	53.15	40.55	44.18	45.51	61.68	81.17	35.28	44.36	75.08
7/7/2016	63.68	52.65	39.85	43.85	45.26	61.23	80.95	35.17	43.92	74.23
7/6/2016	64.91	53.77	40.78	44.97	46.17	63.03	82.54	36.05	44.65	76.12
7/5/2016	65.16	53.76	40.87	44.87	46.08	63.33	82.56	35.90	45.04	76.04
7/1/2016	64.58	53.75	40.39	44.49	45.63	62.80	81.08	35.24	44.40	75.63
6/30/2016	64.63	53.58	39.70	44.80	45.86	63.07	81.06	35.44	44.12	75.66
6/29/2016	63.05	52.50	39.82	43.28	44.84	62.10	79.14	34.41	43.06	73.96
6/28/2016	62.52	52.28	39.81	43.22	44.98	61.93	79.05	34.22	42.99	73.94
6/27/2016	62.01	52.31	39.85	43.18	44.94	61.98	79.13	34.18	42.95	73.39
6/24/2016	61.79	51.79	39.28	42.56	44.36	61.40	77.95	33.73	42.28	72.24
6/23/2016	61.78	51.50	38.80	42.19	43.59	60.93	77.31	33.63	42.05	71.35
6/22/2016	61.09	51.26	38.64	42.02	43.65	60.70	77.08	33.36	42.27	71.48
6/21/2016	61.72	51.37	39.05	42.33	43.71	61.39	77.50	33.70	42.52	71.52
6/20/2016	61.79	51.35	38.89	42.38	43.56	61.07	77.48	33.62	42.41	71.36
6/17/2016	61.09	51.27	38.91	42.45	43.82	61.28	77.78	33.67	42.44	71.42
6/16/2016	61.07	51.20	38.82	42.55	43.71	61.08	77.51	33.91	42.58	71.44
6/15/2016	60.54	50.91	38.68	42.24	43.42	60.60	76.73	33.99	42.17	71.02
6/14/2016	61.41	51.31	39.11	42.76	43.84	61.02	77.41	34.43	42.79	72.25
6/13/2016	60.76	50.76	38.82	42.46	43.31	60.49	76.66	34.29	42.49	71.43
6/10/2016	60.81	50.96	38.99	42.46	43.31	60.65	76.73	34.44	42.67	71.58
6/9/2016	60.99	50.89	39.42	42.42	43.39	60.58	77.17	34.57	42.56	71.67
6/8/2016	60.41	49.68	38.88	41.91	42.83	59.84	76.00	34.27	42.05	70.80
6/7/2016	59.82	49.48	38.52	41.51	42.58	59.23	75.54	33.79	41.56	70.75
6/6/2016	59.36	49.54	38.28	41.55	42.63	59.41	75.26	33.85	41.51	70.99
6/3/2016	59.02	50.00	38.31	41.69	42.82	59.35	75.76	33.85	42.18	71.15

Source: Yahoo! Finance

30-Day Average Closing Prices and Current Dividends
OTP Proxy Group - Party to a Merger or Other Significant Transaction Scenario

	ALE	AEE	LNT	AVA	CMS	EIX	ETR	NWE	PCG	PNM	SCG
Annualized Dividend	2.080	1.700	1.170	1.370	1.250	1.920	3.400	2.000	1.960	0.880	2.300
30 Day Average Closing Stock Price	62.26	51.80	39.38	43.03	44.28	75.34	79.39	61.25	63.20	34.39	72.88
Daily Closing Prices											
7/15/2016	63.74	52.51	39.41	43.44	44.82	77.18	80.28	61.23	64.62	34.26	73.49
7/14/2016	63.48	52.24	39.34	43.35	44.76	77.11	79.79	61.07	64.20	34.13	73.67
7/13/2016	64.29	52.88	39.71	44.00	45.03	77.41	80.92	61.52	64.56	34.70	74.25
7/12/2016	63.67	52.46	39.34	43.53	44.58	76.57	81.06	61.12	63.70	34.53	73.54
7/11/2016	64.36	52.94	40.46	44.23	45.38	77.99	81.01	62.24	64.73	35.10	74.87
7/8/2016	64.30	53.15	40.55	44.18	45.51	78.17	80.88	61.68	64.83	35.28	75.08
7/7/2016	63.68	52.65	39.85	43.85	45.26	77.04	80.50	61.23	64.40	35.17	74.23
7/6/2016	64.91	53.77	40.78	44.97	46.17	78.40	82.03	63.03	65.39	36.05	76.12
7/5/2016	65.16	53.76	40.87	44.87	46.08	78.55	81.73	63.33	64.89	35.90	76.04
7/1/2016	64.58	53.75	40.39	44.49	45.63	77.65	81.61	62.80	64.03	35.24	75.63
6/30/2016	64.63	53.58	39.70	44.80	45.86	77.67	81.35	63.07	63.92	35.44	75.66
6/29/2016	63.05	52.50	39.82	43.28	44.84	76.10	78.84	62.10	62.58	34.41	73.96
6/28/2016	62.52	52.28	39.81	43.22	44.98	76.04	79.15	61.93	62.40	34.22	73.94
6/27/2016	62.01	52.31	39.85	43.18	44.94	76.45	78.91	61.98	63.17	34.18	73.39
6/24/2016	61.79	51.79	39.28	42.56	44.36	74.59	77.99	61.40	62.66	33.73	72.24
6/23/2016	61.78	51.50	38.80	42.19	43.59	73.99	78.29	60.93	62.13	33.63	71.35
6/22/2016	61.09	51.26	38.64	42.02	43.65	73.84	77.88	60.70	62.15	33.36	71.48
6/21/2016	61.72	51.37	39.05	42.33	43.71	74.12	77.95	61.39	62.63	33.70	71.52
6/20/2016	61.79	51.35	38.89	42.38	43.56	73.93	78.11	61.07	62.57	33.62	71.36
6/17/2016	61.09	51.27	38.91	42.45	43.82	74.12	78.65	61.28	63.02	33.67	71.42
6/16/2016	61.07	51.20	38.82	42.55	43.71	73.92	78.45	61.08	62.95	33.91	71.44
6/15/2016	60.54	50.91	38.68	42.24	43.42	73.46	78.08	60.60	62.35	33.99	71.02
6/14/2016	61.41	51.31	39.11	42.76	43.84	74.08	79.01	61.02	62.98	34.43	72.25
6/13/2016	60.76	50.76	38.82	42.46	43.31	73.88	78.35	60.49	62.60	34.29	71.43
6/10/2016	60.81	50.96	38.99	42.46	43.31	73.96	78.65	60.65	63.02	34.44	71.58
6/9/2016	60.99	50.89	39.42	42.42	43.39	73.66	78.68	60.58	62.98	34.57	71.67
6/8/2016	60.41	49.68	38.88	41.91	42.83	72.90	78.61	59.84	62.01	34.27	70.80
6/7/2016	59.82	49.48	38.52	41.51	42.58	72.44	78.42	59.23	61.64	33.79	70.75
6/6/2016	59.36	49.54	38.28	41.55	42.63	72.54	78.33	59.41	61.30	33.85	70.99
6/3/2016	59.02	50.00	38.31	41.69	42.82	72.53	78.24	59.35	61.55	33.85	71.15

Source: Yahoo! Finance

30-Day Average Closing Prices and Current Dividends
OTP Proxy Group - 8.00 Percent Minimum ROE Scenario

	ALE	AEE	LNT	AVA	CMS	IDA	NWE	OGE	PNM	SCG
Annualized Dividend	2.080	1.700	1.170	1.370	1.250	2.040	2.000	1.100	0.880	2.300
30 Day Average Closing Stock Price	62.26	51.80	39.38	43.03	44.28	77.51	61.25	31.56	34.39	72.88
Daily Closing Prices										
7/15/2016	63.74	52.51	39.41	43.44	44.82	80.49	61.23	32.06	34.26	73.49
7/14/2016	63.48	52.24	39.34	43.35	44.76	80.57	61.07	32.06	34.13	73.67
7/13/2016	64.29	52.88	39.71	44.00	45.03	81.37	61.52	32.10	34.70	74.25
7/12/2016	63.67	52.46	39.34	43.53	44.58	80.89	61.12	32.13	34.53	73.54
7/11/2016	64.36	52.94	40.46	44.23	45.38	81.30	62.24	32.39	35.10	74.87
7/8/2016	64.30	53.15	40.55	44.18	45.51	81.31	61.68	32.26	35.28	75.08
7/7/2016	63.68	52.65	39.85	43.85	45.26	80.54	61.23	31.81	35.17	74.23
7/6/2016	64.91	53.77	40.78	44.97	46.17	81.87	63.03	32.33	36.05	76.12
7/5/2016	65.16	53.76	40.87	44.87	46.08	81.87	63.33	32.56	35.90	76.04
7/1/2016	64.58	53.75	40.39	44.49	45.63	81.44	62.80	32.61	35.24	75.63
6/30/2016	64.63	53.58	39.70	44.80	45.86	81.35	63.07	32.75	35.44	75.66
6/29/2016	63.05	52.50	39.82	43.28	44.84	79.10	62.10	32.04	34.41	73.96
6/28/2016	62.52	52.28	39.81	43.22	44.98	78.13	61.93	31.55	34.22	73.94
6/27/2016	62.01	52.31	39.85	43.18	44.94	77.09	61.98	31.07	34.18	73.39
6/24/2016	61.79	51.79	39.28	42.56	44.36	75.61	61.40	31.46	33.73	72.24
6/23/2016	61.78	51.50	38.80	42.19	43.59	75.27	60.93	31.24	33.63	71.35
6/22/2016	61.09	51.26	38.64	42.02	43.65	74.46	60.70	30.79	33.36	71.48
6/21/2016	61.72	51.37	39.05	42.33	43.71	75.26	61.39	31.15	33.70	71.52
6/20/2016	61.79	51.35	38.89	42.38	43.56	75.02	61.07	30.99	33.62	71.36
6/17/2016	61.09	51.27	38.91	42.45	43.82	75.00	61.28	31.02	33.67	71.42
6/16/2016	61.07	51.20	38.82	42.55	43.71	75.10	61.08	30.93	33.91	71.44
6/15/2016	60.54	50.91	38.68	42.24	43.42	74.64	60.60	30.68	33.99	71.02
6/14/2016	61.41	51.31	39.11	42.76	43.84	75.50	61.02	30.80	34.43	72.25
6/13/2016	60.76	50.76	38.82	42.46	43.31	74.96	60.49	31.02	34.29	71.43
6/10/2016	60.81	50.96	38.99	42.46	43.31	75.38	60.65	30.94	34.44	71.58
6/9/2016	60.99	50.89	39.42	42.42	43.39	74.98	60.58	31.48	34.57	71.67
6/8/2016	60.41	49.68	38.88	41.91	42.83	74.46	59.84	31.16	34.27	70.80
6/7/2016	59.82	49.48	38.52	41.51	42.58	74.00	59.23	31.19	33.79	70.75
6/6/2016	59.36	49.54	38.28	41.55	42.63	73.99	59.41	31.29	33.85	70.99
6/3/2016	59.02	50.00	38.31	41.69	42.82	74.23	59.35	30.96	33.85	71.15

Source: Yahoo! Finance

DOC CAPM and ECAPM Analyses Using 30 Year Treasury Yields

	Line No.	Formula/Note	
Risk-free Rate (30 year)	[1]	DOC Ex.___JPK-12, Schedule 2	2.38%
Thomson First Call Projected S&P Earnings Growth Rate	[2]	DOC Ex.___JPK-4, Schedule 3	7.64%
Dividend Yield on S&P 500	[3]	DOC Ex.___JPK-4, Schedule 4	2.05%
Dividend Yield on S&P 500 with One Half Years' Worth of Growth	[4]	= [3] x (1+[2])^0.5	2.13%
DCF Required Market Return	[5]	= [2] + [4]	9.77%
β	[6]	DOC Ex. ___ JPK-4, Schedule 5	0.75
Required Return for OTP (Simple CAPM)	[7]	= [1] + [6] x ([5] - [1])	7.89%
Flotation Cost Adjustment	[8]	DOC Ex. ___ JPK-3, Schedule 7	0.13%
Simple CAPM with Flotation Costs	[9]	= [7] = [8]	8.02%
Expected Return for MERC (ECAPM)	[10]	= [1]+ 0.25([5]-[1])+ 0.75([6])([5]-[1])	8.36%
Flotation Cost Adjustment	[11]	DOC Ex. ___ JPK-3, Schedule 7	0.13%
ECAPM with Flotation Costs	[12]	= [10] + [11]	8.49%

30-Year Treasury
Constant Maturity Date

Line No.	Date	Rate
		(%)
1.	2016-06-01	2.63
2.	2016-06-02	2.58
3.	2016-06-03	2.52
4.	2016-06-06	2.55
5.	2016-06-07	2.54
6.	2016-06-08	2.51
7.	2016-06-09	2.48
8.	2016-06-10	2.44
9.	2016-06-13	2.43
10.	2016-06-14	2.43
11.	2016-06-15	2.43
12.	2016-06-16	2.39
13.	2016-06-17	2.43
14.	2016-06-20	2.47
15.	2016-06-21	2.50
16.	2016-06-22	2.50
17.	2016-06-23	2.55
18.	2016-06-24	2.42
19.	2016-06-27	2.28
20.	2016-06-28	2.27
21.	2016-06-29	2.30
22.	2016-06-30	2.30
23.	2016-07-01	2.24
24.	2016-07-05	2.14
25.	2016-07-06	2.14
26.	2016-07-07	2.14
27.	2016-07-08	2.11
28.	2016-07-11	2.14
29.	2016-07-12	2.24
30.	2016-07-13	2.18
31.	Average	2.38

Source:
Federal Reserve Bank of St. Louis

Supreme Court of the United States
BLUEFIELD WATERWORKS & IMPROVEMENT CO.
v.
PUBLIC SERVICE COMMISSION OF WEST VIRGINIA et al.
No. 256.

Argued January 22, 1923.
Decided June 11, 1923.

In Error to the Supreme Court of Appeals of West Virginia.

Proceedings by the Bluefield Waterworks & Improvement Company against the Public Service Commission of the State of West Virginia and others to suspend and set aside an order of the Commission fixing rates. From a judgment of the Supreme Court of West Virginia, dismissing the petition, and denying the relief (89 W. Va. 736, 110 S. E. 205), the Waterworks Company bring error. Reversed.

West Headnotes

Constitutional Law 92 298(1.5)

92 Constitutional Law
92XII Due Process of Law
92k298 Regulation of Charges and Prices
92k298(1.5) k. Public Utilities in General. Most Cited Cases

Rates which are not sufficient to yield a reasonable return on the value of the property used in public service at the time it is being so used to render the service are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property, in violation of the Fourteenth Amendment of the Constitution.

Constitutional Law 92 298(3)

92 Constitutional Law
92XII Due Process of Law
92k298 Regulation of Charges and Prices
92k298(3) k. Water and Irrigation Companies. Most Cited Cases

Under the due process clause of the Fourteenth Amendment of the Constitution, U.S.C.A., a waterworks company is entitled to the independent judgment of the court as to both law and facts, where the question is whether the rates fixed by a public service commission are confiscatory.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness of Charges. Most Cited Cases

It was error for a state public service commission, in arriving at the value of the property used in public service, for the purpose of fixing the rates, to fail to give proper weight to the greatly increased cost of construction since the war.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness of Charges. Most Cited Cases

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to such profits as are realized or anticipated in highly profitable enterprises or speculative ventures.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness

of Charges. Most Cited Cases
Since the investors take into account the result of past operations as well as present rates in determining whether they will invest, a waterworks company which had been earning a low rate of returns through a long period up to the time of the inquiry is entitled to return of more than 6 per cent. on the value of its property used in the public service, in order to justly compensate it for the use of its property.

Federal Courts 170B 504.1

170B Federal Courts
170BVII Supreme Court
170BVII(E) Review of Decisions of State Courts
170Bk504 Nature of Decisions or Questions Involved
170Bk504.1 k. In General. Most Cited Cases
(Formerly 106k394(6))
A proceeding in a state court attacking an order of a public service commission fixing rates, on the ground that the rates were confiscatory and the order void under the federal Constitution, is one where there is drawn in question the validity of authority exercised under the state, on the ground of repugnancy to the federal Constitution, and therefore is reviewable by writ of error.

****675 *680** Messrs. Alfred G. Fox and Jos. M. Sanders, both of Bluefield, W. Va., for plaintiff in error.
Mr. Russell S. Ritz, of Bluefield, W. Va., for defendants in error.

***683** Mr. Justice BUTLER delivered the opinion of the Court.
Plaintiff in error is a corporation furnishing water to the city of Bluefield, W. Va., ****676** and its inhabitants. September 27, 1920, the Public Service Commission of the state, being authorized by statute to fix just and reasonable rates, made its order prescribing rates. In accordance with the laws of the state (section 16, c. 15-O, Code of West Virginia [sec. 651]), the company instituted proceedings in the Supreme Court of Appeals to suspend and set aside the order. The petition alleges that the order is repugnant to the Fourteenth Amendment, and deprives the company of its property without just compensation and without due process of law, and denies it equal protection of the laws. A final judgment was entered, denying the company relief and dismissing its petition. The case is here on writ of error.

[1] 1. The city moves to dismiss the writ of error for the reason, as it asserts, that there was not drawn in question the validity of a statute or an authority exercised under the state, on the ground of repugnancy to the federal Constitution.

The validity of the order prescribing the rates was directly challenged on constitutional grounds, and it was held valid by the highest court of the state. The prescribing of rates is a legislative act. The commission is an instrumentality of the state, exercising delegated powers. Its order is of the same force as would be a like enactment by the Legislature. If, as alleged, the prescribed rates are confiscatory, the order is void. Plaintiff in error is entitled to bring the case here on writ of error and to have that question decided by this court. The motion to dismiss will be denied. See ***684**Oklahoma Natural Gas Co. v. Russell, 261 U. S. 290, 43 Sup. Ct. 353, 67 L. Ed. 659, decided March 5, 1923, and cases cited; also Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 40 Sup. Ct. 527, 64 L. Ed. 908.

2. The commission fixed $460,000 as the amount on which the company is entitled to a return. It found that under existing rates, assuming some increase of business, gross earnings for 1921 would be $80,000 and operating expenses $53,000 leaving $27,000, the equivalent of 5.87 per cent., or 3.87 per cent. after deducting 2 per cent. allowed for depreciation. It held existing rates insufficient to the extent of 10,000. Its order allowed the company to add 16 per cent. to all bills, excepting those for public and private fire protection. The total of the bills so to be increased amounted to $64,000; that is, 80 per cent. of the revenue was authorized to be increased 16 per cent., equal to an increase of 12.8 per cent. on the total, amounting to $10,240.

As to value: The company claims that the value of the property is greatly in excess of $460,000. Reference to the evidence is necessary. There was submitted to the commission evidence of value which it summarized substantially as follows:

a. Estimate by company's engineer

	on. basis of reproduction new, less. depreciation, at prewar prices.	$ 624,548 00
b.	Estimate by company's engineer on. basis of reproduction new, less. depreciation, at 1920 prices.	1,194,663 00
c.	Testimony of company's engineer. fixing present fair value for rate. making purposes.	900,000 00
d.	Estimate by commissioner's engineer on. basis of reproduction new, less. depreciation at 1915 prices, plus. additions since December 31, 1915, at. actual cost, excluding Bluefield. Valley waterworks, water rights,. and going value.	397,964 38
e.	Report of commission's statistician. showing investment cost less. depreciation.	365,445 13
f.	Commission's valuation, as fixed in. case No. 368 ($360,000), plus gross. additions to capital since made. ($92,520.53).	452,520 53

***685** It was shown that the prices prevailing in 1920 were nearly double those in 1915 and pre-war time. The company did not claim value as high as its estimate of cost of construction in 1920. Its valuation engineer testified that in his opinion the value of the property was $900,000-a figure between the cost of construction in 1920, less depreciation, and the cost of construction in 1915 and before the war, less depreciation.

The commission's application of the evidence may be stated briefly as follows:

As to ‘a,’ supra: The commission deducted $204,000 from the estimate (details printed in the margin), [FN1] leaving approximately $421,000, which it contrasted with the estimate of its own engineer, $397,964.38 (see ‘d,’ supra). It found that there should be included $25,000 for the Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital. If these be added to $421,000, there results $500,600. This may be compared with the commission's final figure, $460,000.

FN1

Difference in depreciation allowed.	$ 49,000
Preliminary organization and development. cost.	14,500
Bluefield Valley waterworks plant.	25,000
Water rights.	50,000
Excess overhead costs.	39,000
Paving over mains.	28,500
	$204,000

***686** As to 'b' and 'c,' supra: These were given no weight by the commission in arriving at its final figure, $460,000. It said:

'Applicant's plant was originally constructed more than twenty years ago, and has been added to from time to time as the progress and development of the community required. For this reason, it would be unfair to its consumers to use as a basis for present fair value the abnormal prices prevailing during the recent war period; but, when, as in this case, a part of the plant has been constructed or added to during that period, in fairness to the applicant, consideration must be given to the cost of such expenditures made to meet the demands of the public.'

****677** As to 'd,' supra: The commission, taking $400,000 (round figures), added $25,000 for Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital, making $477,500. This may be compared with its final figure, $460,000.

As to 'e,' supra: The commission, on the report of its statistician, found gross investment to be $500,402.53. Its engineer, applying the straight line method, found 19 per cent. depreciation. It applied 81 per cent. to gross investment and added 10 per cent. for going value and $10,000 for working capital, producing $455,500. FN2 This may be compared with its final figure, $460,000.

FN2 As to 'e': $365,445.13 represents investment cost less depreciation. The gross investment was found to be $500,402.53, indicating a deduction on account of depreciation of $134,957.40, about 27 per cent., as against 19 per cent. found by the commission's engineer.

As to 'f,' supra: It is necessary briefly to explain how this figure, $452,520.53, was arrived at. Case No. 368 was a proceeding initiated by the application of the company for higher rates, April 24, 1915. The commission made a valuation as of January 1, 1915. There were presented two estimates of reproduction cost less depreciation, one by a valuation engineer engaged by the company, ***687** and the other by a valuation engineer engaged by the city, both 'using the same method.' An inventory made by the company's engineer was accepted as correct by the city and by the commission. The method 'was that generally employed by courts and commissions in arriving at the value of public utility properties under this method.' and in both estimates 'five year average unit prices' were applied. The estimate of the company's engineer was $540,000 and of the city's engineer, $392,000. The principal differences as given by the commission are shown in the margin. FN3 The commission disregarded both estimates and arrived at $360,000. It held that the best basis of valuation was the net investment, i. e., the total cost of the property less depreciation. It said:

FN3

		Company Engineer.	City Engineer.
1.	Preliminary costs.	$14,455	$1,000
2.	Water rights.	50,000	Nothing
3.	Cutting pavements over. mains.	27,744	233
4.	Pipe lines from gravity. springs.	22,072	15,442
5.	Laying cast iron street. mains.	19,252	15,212
6.	Reproducing Ada springs.	18,558	13,027
7.	Superintendence and. engineering.	20,515	13,621
8.	General contingent cost.	16,415	5,448
		$189,011	$63,983

'The books of the company show a total gross investment, since its organization, of $407,882, and that there has been charged off for depreciation from year to year the total sum of $83,445, leaving a net investment of

$324,427. * * * From an examination of the books * * * it appears that the records of the company have been remarkably well kept and preserved. It therefore seems that, when a plant is developed under these conditions, the net investment, which, of course, means the total gross investment less depreciation, is the very best basis of valuation for rate making purposes and that the other methods above referred to should ***688** be used only when it is impossible to arrive at the true investment. Therefore, after making due allowance for capital necessary for the conduct of the business and considering the plant as a going concern, it is the opinion of the commission that the fair value for the purpose of determining reasonable and just rates in this case of the property of the applicant company, used by it in the public service of supplying water to the city of Bluefield and its citizens, is the sum of $360,000, which sum is hereby fixed and determined by the commission to be the fair present value for the said purpose of determining the reasonable and just rates in this case.'

In its report in No. 368, the commission did not indicate the amounts respectively allowed for going value or working capital. If 10 per cent. be added for the former, and $10,000 for the latter (as fixed by the commission in the present case), there is produced $366,870, to be compared with $360,000, found by the commission in its valuation as of January 1, 1915. To this it added $92,520.53, expended since, producing $452,520.53. This may be compared with its final figure, $460,000.

The state Supreme Court of Appeals holds that the valuing of the property of a public utility corporation and prescribing rates are purely legislative acts, not subject to judicial review, except in so far as may be necessary to determine whether such rates are void on constitutional or other grounds, and that findings of fact by the commission based on evidence to support them will not be reviewed by the court. City of Bluefield v. Waterworks, 81 W. Va. 201, 204, 94 S. E. 121; Coal & Coke Co. v. Public Service Commission, 84 W. Va. 662, 678, 100 S. E. 557, 7 A. L. R. 108; Charleston v. Public Service Commission, 86 W. Va. 536, 103 S. E. 673.

In this case (89 W. Va. 736, 738, 110 S. E. 205, 206) it said:
'From the written opinion of the commission we find that it ascertained the value of the petitioner's property for rate making [then quoting the commission] 'after ***689** maturely and carefully considering the various methods presented for the ascertainment of fair value and giving such weight as seems proper to every element involved and all the facts and circumstances disclosed by the record.''

[2] [3] The record clearly shows that the commission, in arriving at its final figure, did not accord proper, if any, weight to the greatly enhanced costs of construction in 1920 over those prevailing about 1915 and before the war, as established by uncontradicted ****678** evidence; and the company's detailed estimated cost of reproduction new, less depreciation, at 1920 prices, appears to have been wholly disregarded. This was erroneous. Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U. S. 276, 43 Sup. Ct. 544, 67 L. Ed. 981, decided May 21, 1923. Plaintiff in error is entitled under the due process clause of the Fourteenth Amendment to the independent judgment of the court as to both law and facts. Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 289, 40 Sup. Ct. 527, 64 L. Ed. 908, and cases cited.

We quote further from the court's opinion (89 W. Va. 739, 740, 110 S. E. 206):
'In our opinion the commission was justified by the law and by the facts in finding as a basis for rate making the sum of $460,000.00. * * * In our case of Coal & Coke Ry. Co. v. Conley, 67 W. Va. 129, it is said: 'It seems to be generally held that, in the absence of peculiar and extraordinary conditions, such as a more costly plant than the public service of the community requires, or the erection of a plant at an actual, though extravagant, cost, or the purchase of one at an exorbitant or inflated price, the actual amount of money invested is to be taken as the basis, and upon this a return must be allowed equivalent to that which is ordinarily received in the locality in which the business is done, upon capital invested in similar enterprises. In addition to this, consideration must be given to the nature of the investment, a higher rate ***690** being regarded as justified by the risk incident to a hazardous investment.'
'That the original cost considered in connection with the history and growth of the utility and the value of the services rendered constitute the principal elements to be considered in connection with rate making, seems to be supported by nearly all the authorities.'

[4] The question in the case is whether the rates prescribed in the commission's order are confiscatory and therefore beyond legislative power. Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. This is so well settled by numerous decisions of this court that citation of the cases is scarcely necessary:

'What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience.' Smyth v. Ames (1898) 169 U. S. 467, 547, 18 Sup. Ct. 418, 434 (42 L. Ed. 819).
'There must be a fair return upon the reasonable value of the property at the time it is being used for the public. * * * And we concur with the court below in holding that the value of the property is to be determined as of the time when the inquiry is made regarding the rates. If the property, which legally enters into the consideration of the question of rates, has increased in value since it was acquired, the company is entitled to the benefit of such increase.' Willcox v. Consolidated Gas Co. (1909) 212 U. S. 19, 41, 52, 29 Sup. Ct. 192, 200 (53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. [N. S.] 1134).
'The ascertainment of that value is not controlled by artificial rules. It is not a matter of formulas, but there must be a reasonable judgment having its basis in a proper consideration of all relevant facts.' Minnesota Rate Cases (1913) 230 U. S. 352, 434, 33 Sup. Ct. 729, 754 (57 L. Ed. 1511, 48 L. R. A. [N. S.] 1151, Ann. Cas. 1916A, 18).
***691** 'And in order to ascertain that value, the original cost of construction, the amount expended in permanent improvements, the amount and market value of its bonds and stock, the present as compared with the original cost of construction, the probable earning capacity of the property under particular rates prescribed by statute, and the sum required to meet operating expenses, are all matters for consideration, and are to be given such weight as may be just and right in each case. We do not say that there may not be other matters to be regarded in estimating the value of the property.' Smyth v. Ames, 169 U. S., 546, 547, 18 Sup. Ct. 434, 42 L. Ed. 819.
'* * * The making of a just return for the use of the property involves the recognition of its fair value if it be more than its cost. The property is held in private ownership and it is that property, and not the original cost of it, of which the owner may not be deprived without due process of law.'

Minnesota Rate Cases, 230 U. S. 454, 33 Sup. Ct. 762, 57 L. Ed. 1511, 48 L. R. A. (N. S.) 1151, Ann. Cas. 1916A, 18.

In Missouri ex rel. Southwestern Bell Telephone Co., v. Public Service Commission of Missouri, supra, applying the principles of the cases above cited and others, this court said:
'Obviously, the commission undertook to value the property without according any weight to the greatly enhanced costs of material, labor, supplies, etc., over those prevailing in 1913, 1914, and 1916. As matter of common knowledge, these increases were large. Competent witnesses estimated them as 45 to 50 per centum. * * * It is impossible to ascertain what will amount to a fair return upon properties devoted to public service, without giving consideration to the cost of labor, supplies, etc., at the time the investigation is made. An honest and intelligent forecast of probable future values, made upon a view of all the relevant circumstances, is essential. If the highly important element of present costs is wholly disregarded, such a forecast becomes impossible. Estimates for to-morrow cannot ignore prices of to-day.'

[5] ***692** It is clear that the court also failed to give proper consideration to the higher cost of construction in 1920 over that in 1915 and before the war, and failed to give weight to cost of reproduction less depreciation on the basis of 1920 prices, or to the testimony of the company's valuation engineer, based on present and past costs of construction, that the property in his opinion, was worth $900,000. The final figure, $460,000, was arrived ****679** at substantially on the basis of actual cost, less depreciation, plus 10 per cent. for going value and $10,000 for working capital. This resulted in a valuation considerably and materially less than would have been reached by a fair and just consideration of all the facts. The valuation cannot be sustained. Other objections to the valuation need not be considered.

3. Rate of return: The state commission found that the company's net annual income should be approximately $37,000, in order to enable it to earn 8 per cent. for return and depreciation upon the value of its property as fixed by it. Deducting 2 per cent. for depreciation, there remains 6 per cent. on $460,000, amounting to $27,600 for return. This was approved by the state court.

[6] The company contends that the rate of return is too low and confiscatory. What annual rate will constitute just compensation depeds upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in ***693** highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A

rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

In 1909, this court, in Willcox v. Consolidated Gas Co., 212 U. S. 19, 48-50, 29 Sup. Ct. 192, 53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. (N. S.) 1134, held that the question whether a rate yields such a return as not to be confiscatory depends upon circumstances, locality and risk, and that no proper rate can be established for all cases; and that, under the circumstances of that case, 6 per cent. was a fair return on the value of the property employed in supplying gas to the city of New York, and that a rate yielding that return was not confiscatory. In that case the investment was held to be safe, returns certain and risk reduced almost to a minimum-as nearly a safe and secure investment as could be imagined in regard to any private manufacturing enterprise.

In 1912, in Cedar Rapids Gas Co. v. Cedar Rapids, 223 U. S. 655, 670, 32 Sup. Ct. 389, 56 L. Ed. 594, this court declined to reverse the state court where the value of the plant considerably exceeded its cost, and the estimated return was over 6 per cent.

In 1915, in Des Moines Gas Co. v. Des Moines, 238 U. S. 153, 172, 35 Sup. Ct. 811, 59 L. Ed. 1244, this court declined to reverse the United States District Court in refusing an injunction upon the conclusion reached that a return of 6 per cent. per annum upon the value would not be confiscatory.

In 1919, this court in Lincoln Gas Co. v. Lincoln, 250 U. S. 256, 268, 39 Sup. Ct. 454, 458 (63 L. Ed. 968), declined on the facts of that case to approve a finding that no rate yielding as much as 6 per cent. ***694** on the invested capital could be regarded as confiscatory. Speaking for the court, Mr. Justice Pitney said:
'It is a matter of common knowledge that, owing principally to the World War, the costs of labor and supplies of every kind have greatly advanced since the ordinance was adopted, and largely since this cause was last heard in the court below. And it is equally well known that annual returns upon capital and enterprise the world over have materially increased, so that what would have been a proper rate of return for capital invested in gas plants and similar public utilities a few years ago furnishes no safe criterion for the present or for the future.'

In 1921, in Brush Electric Co. v. Galveston, the United States District Court held 8 per cent. a fair rate of return. [FN4]

FN4 This case was affirmed by this court June 4, 1923, 262 U. S. 443, 43 Sup. Ct. 606, 67 L. Ed. 1076.

In January, 1923, in City of Minneapolis v. Rand, the Circuit Court of Appeals of the Eighth Circuit (285 Fed. 818, 830) sustained, as against the attack of the city on the ground that it was excessive, 7 1/2 per cent., found by a special master and approved by the District Court as a fair and reasonable return on the capital investment-the value of the property.

[7] Investors take into account the result of past operations, especially in recent years, when determining the terms upon which they will invest in such an undertaking. Low, uncertain, or irregular income makes for low prices for the securities of the utility and higher rates of interest to be demanded by investors. The fact that the company may not insist as a matter of constitutional right that past losses be made up by rates to be applied in the present and future tends to weaken credit, and the fact that the utility is protected against being compelled to serve for confiscatory rates tends to support it. In ***695** this case the record shows that the rate of return has been low through a long period up to the time of the inquiry by the commission here involved. For example, the average rate of return on the total cost of the property from 1895 to 1915, inclusive, was less than 5 per cent.; from 1911 to 1915, inclusive, about 4.4 per cent., without allowance for depreciation. In 1919 the net operating income was approximately $24,700, leaving $15,500, approximately, or 3.4 per cent. on $460,000 fixed by the commission, after deducting 2 per cent. for depreciation. In 1920, the net operating income was approximately $25,465, leaving $16,265 for return, after allowing for depreciation. Under the facts and circumstances indicated by the record, we think that a rate of return of 6 per cent. upon the value of the property is substantially too low to constitute just compensation for the use of the property employed to render the service.

The judgment of the Supreme Court of Appeals of West Virginia is reversed.

Mr. Justice BRANDEIS concurs in the judgment of reversal, for the reasons stated by him in Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, supra.
U.S. 1923
Bluefield Waterworks & Imp. Co. v. Public Service Commission of W. Va.
P.U.R. 1923D 11, 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176

END OF DOCUMENT

Supreme Court of the United States
FEDERAL POWER COMMISSION et al.
v.
HOPE NATURAL GAS CO.
CITY OF CLEVELAND
v.
SAME.
Nos. 34 and 35.

Argued Oct. 20, 21, 1943.
Decided Jan. 3, 1944.

Separate proceedings before the Federal Power Commission by such Commission, by the City of Cleveland and the City of Akron, and by Pennsylvania Public Utility Commission wherein the State of West Virginia and its Public Service Commission were permitted to intervene concerning rates charged by Hope Natural Gas Company which were consolidated for hearing. An order fixing rates was reversed and remanded with directions by the Circuit Court of Appeals, 134 F.2d 287, and Federal Power Commission, City of Akron and Pennsylvania Public Utility Commission in one case and the City of Cleveland in another bring certiorari.

Reversed.

Mr. Justice REED, Mr. Justice FRANKFURTER and Mr. Justice JACKSON, dissenting.

On Writs of Certiorari to the United States Circuit Court of Appeals for the Fourth Circuit.

West Headnotes

[1] **Public Utilities 317A 120**

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak120 k. Nature and Extent in General. Most Cited Cases
(Formerly 317Ak7.1, 317Ak7)
Rate-making is only one species of price-fixing which, like other applications of the police power, may reduce the value of the property regulated, but that does not render the regulation invalid.

[2] **Public Utilities 317A 123**

317A Public Utilities
317AII Regulation
317Ak119 Regulation of Charges
317Ak123 k. Reasonableness of Charges in General. Most Cited Cases
(Formerly 317Ak7.4, 317Ak7)
Rates cannot be made to depend upon fair value, which is the end product of the process of rate-making and not the starting point, when the value of the going enterprise depends on earnings under whatever rates may be anticipated.

[3] **Gas 190 14.3(2)**

190 Gas
190k14 Charges
190k14.3 Administrative Regulation
190k14.3(2) k. Federal Power Commission. Most Cited Cases
(Formerly 190k14(1))
The rate-making function of the Federal Power Commission under the Natural Gas Act involves the making of pragmatic adjustments, and the Commission is not bound to the use of any single formula or combination of formulae in determining rates. Natural Gas Act, § § 4(a), 5(a), 6, 15 U.S.C.A. § § 717c(a), 717d(a), 717e.

[4] **Gas 190 14.5(6)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(6) k. Scope of Review and Trial De Novo. Most Cited Cases
(Formerly 190k14(1))
When order of Federal Power Commission fixing natural gas rates is challenged in the courts, the question is whether order viewed in its entirety meets the requirements of the Natural Gas Act. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[5] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges

190k14.4(1) k. In General. Most Cited Cases

(Formerly 190k14(1))

Under the statutory standard that natural gas rates shall be "just and reasonable" it is the result reached and not the method employed that is controlling. Natural Gas Act § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[6] Gas 190 14.5(6)

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(6) k. Scope of Review and Trial De Novo. Most Cited Cases

(Formerly 190k14(1))

If the total effect of natural gas rates fixed by Federal Power Commission cannot be said to be unjust and unreasonable, judicial inquiry under the Natural Gas Act is at an end. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[7] Gas 190 14.5(7)

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(7) k. Presumptions. Most Cited Cases

(Formerly 190k14(1))

An order of the Federal Power Commission fixing rates for natural gas is the product of expert judgment, which carries a presumption of validity, and one who would upset the rate must make a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[8] Gas 190 14.4(1)

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases

(Formerly 190k14(1))

The fixing of just and reasonable rates for natural gas by the Federal Power Commission involves a balancing of the investor and the consumer interests. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[9] Gas 190 14.4(9)

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases

(Formerly 190k14(1))

As respects rates for natural gas, from the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business, which includes service on the debt and dividends on stock, and by such standard the return to the equity owner should be commensurate with the terms on investments in other enterprises having corresponding risks, and such returns should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[10] Gas 190 14.4(9)

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases

(Formerly 190k14(1))

The fixing by the Federal Power Commission of a rate of return that permitted a natural gas company to earn $2,191,314 annually was supported by substantial evidence. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[11] Gas 190 14.4(9)

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases

(Formerly 190k14(1))

Rates which enable a natural gas company to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed cannot be condemned as invalid, even though they might produce only a meager return on the so-called "fair value" rate base. Natural Gas Act,

§ § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[12] **Gas 190 14.4(4)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(4) k. Method of Valuation. Most Cited Cases
(Formerly 190k14(1))
A return of only 3 27/100 per cent. on alleged rate base computed on reproduction cost new to natural gas company earning an annual average return of about 9 per cent. on average investment and satisfied with existing gas rates suggests an inflation of the base on which the rate had been computed, and justified Federal Power Commission in rejecting reproduction cost as the measure of the rate base. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[13] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
There is no constitutional requirement that owner who engages in a wasting-asset business of limited life shall receive at the end more than he has put into it, and such rule is applicable to a natural gas company since the ultimate exhaustion of its supply of gas is inevitable. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[14] **Gas 190 14.4(9)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(9) k. Depreciation and Depletion. Most Cited Cases
(Formerly 190k14(1))
In fixing natural gas rate the basing of annual depreciation on cost is proper since by such procedure the utility is made whole and the integrity of its investment is maintained, and no more is required. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[15] **Gas 190 14.3(4)**

190 Gas
190k14 Charges
190k14.3 Administrative Regulation
190k14.3(4) k. Findings and Orders. Most Cited Cases
(Formerly 190k14(1))
There are no constitutional requirements more exacting than the standards of the Natural Gas Act which are that gas rates shall be just and reasonable, and a rate order which conforms with the act is valid. Natural Gas Act, § § 4(a), 5(a), 6, 19(b), 15 U.S.C.A. § § 717c(a), 717d(a), 717e, 717r(b).

[16] **Commerce 83 62.2**

83 Commerce
83II Application to Particular Subjects and Methods of Regulation
83II(B) Conduct of Business in General
83k62.2 k. Gas. Most Cited Cases
(Formerly 83k13)
The purpose of the Natural Gas Act was to provide through the exercise of the national power over interstate commerce an agency for regulating the wholesale distribution to public service companies of natural gas moving in interstate commerce not subject to certain types of state regulation, and the act was not intended to take any authority from state commissions or to usurp state regulatory authority. Natural Gas Act, § 1 et seq., 15 U.S.C.A. § 717 et seq.

[17] **Mines and Minerals 260 92.5(3)**

260 Mines and Minerals
260III Operation of Mines, Quarries, and Wells
260III(A) Statutory and Official Regulations
260k92.5 Federal Law and Regulations
260k92.5(3) k. Oil and Gas. Most Cited Cases
(Formerly 260k92.7, 260k92)
Under the Natural Gas Act, the Federal Power Commission has no authority over the production or gathering of natural gas. Natural Gas Act, § 1(b), 15 U.S.C.A. § 717(b).

[18] **Gas 190 14.1(1)**

190 Gas
190k14 Charges
190k14.1 In General
190k14.1(1) k. In General; Amount and

Regulation. Most Cited Cases
(Formerly 190k14(1))
The primary aim of the Natural Gas Act was to protect consumers against exploitation at the hands of natural gas companies and holding companies owning a majority of the pipe-line mileage which moved gas in interstate commerce and against which state commissions, independent producers and communities were growing quite helpless. Natural Gas Act, § § 4, 6-10, 14, 15 U.S.C.A. § § 717c, 717e-717i, 717m.

[19] **Gas 190 14.1(1)**

190 Gas
190k14 Charges
190k14.1 In General
190k14.1(1) k. In General; Amount and Regulation. Most Cited Cases
(Formerly 190k14(1))
Apart from the express exemptions contained in § 7 of the Natural Gas Act considerations of conservation are material where abandonment or extensions of facilities or service by natural gas companies are involved, but exploitation of consumers by private operators through maintenance of high rates cannot be continued because of the indirect benefits derived therefrom by a state containing natural gas deposits. Natural Gas Act, § § 4, 5, and § 7 as amended 15 U.S.C.A. § § 717c, 717d, 717f.

[20] **Commerce 83 62.2**

83 Commerce
83II Application to Particular Subjects and Methods of Regulation
83II(B) Conduct of Business in General
83k62.2 k. Gas. Most Cited Cases
(Formerly 83k13)
A limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state, either to safeguard its tax revenues from such industry, or to protect the interests of those who sell their gas to the interstate operator, particularly where the return allowed the company by the Federal Power Commission was a net return after all such charges. Natural Gas Act, § § 4, 5, and § 7, as amended, 15 U.S.C.A. § § 717c, 717d, 717f.

[21] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The Natural Gas Act granting Federal Power Commission power to fix "just and reasonable rates" does not include the power to fix rates which will disallow or discourage resales for industrial use. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[22] **Gas 190 14.4(1)**

190 Gas
190k14 Charges
190k14.4 Reasonableness of Charges
190k14.4(1) k. In General. Most Cited Cases
(Formerly 190k14(1))
The wasting-asset nature of the natural gas industry does not require the maintenance of the level of rates so that natural gas companies can make a greater profit on each unit of gas sold. Natural Gas Act, § § 4(a), 5(a), 15 U.S.C.A. § § 717c(a), 717d(a).

[23] **Federal Courts 170B 452**

170B Federal Courts
170BVII Supreme Court
170BVII(B) Review of Decisions of Courts of Appeals
170Bk452 k. Certiorari in General. Most Cited Cases
(Formerly 106k383(1))
Where the Federal Power Commission made no findings as to any discrimination or unreasonable differences in rates, and its failure was not challenged in the petition to review, and had not been raised or argued by any party, the problem of discrimination was not open to review by the Supreme Court on certiorari. Natural Gas Act, § 4(b), 15 U.S.C.A. § 717c(b).

[24] **Constitutional Law 92 74**

92 Constitutional Law
92III Distribution of Governmental Powers and Functions
92III(B) Judicial Powers and Functions
92k71 Encroachment on Executive
92k74 k. Powers, Duties, and Acts Under Legislative Authority. Most Cited Cases
(Formerly 15Ak226)
Congress has entrusted the administration of the

Natural Gas Act to the Federal Power Commission and not to the courts, and apart from the requirements of judicial review, it is not for the Supreme Court to advise the Commission how to discharge its functions. Natural Gas Act, § § 1 et seq., 19(b), 15 U.S.C.A. § § 717 et seq., 717r(b).

[25] **Gas 190 ⚿14.5(3)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(3) k. Decisions Reviewable. Most Cited Cases
(Formerly 190k14(1))

Under the Natural Gas Act, where order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action, the order is not reviewable, and resort to the courts in such situation is either premature or wholly beyond the province of such courts. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

[26] **Gas 190 ⚿14.5(4)**

190 Gas
190k14 Charges
190k14.5 Judicial Review and Enforcement of Regulations
190k14.5(4) k. Persons Entitled to Relief; Parties. Most Cited Cases
(Formerly 190k14(1))

Findings of the Federal Power Commission on lawfulness of past natural gas rates, which the Commission was without power to enforce, were not reviewable under the Natural Gas Act giving any "party aggrieved" by an order of the Commission the right of review. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

****283 *592** Mr. Francis M. Shea, Asst. Atty. Gen., for petitioners Federal Power Com'n and others.
***593** Mr. Spencer W. Reeder, of Cleveland, Ohio, for petitioner City of cleveland.
Mr. William B. Cockley, of Cleveland, Ohio, for respondent.
Mr. M. M. Neeley, of Charleston, W. Va., for State of West Virginia, as amicus curiae by special leave of Court.

Mr. Justice DOUGLAS delivered the opinion of the Court.

The primary issue in these cases concerns the validity under the Natural Gas Act of 1938, 52 Stat. 821, 15 U.S.C. s 717 et seq., 15 U.S.C.A. s 717 et seq., of a rate order issued by the Federal Power Commission reducing the rates chargeable by Hope Natural Gas Co., 44 P.U.R.,N.S., 1. On a petition for review of the order made pursuant to s 19(b) of the Act, the ***594** Circuit Court of Appeals set it aside, one judge dissenting. 4 Cir., 134 F.2d 287. The cases ****284** are here on petitions for writs of certiorari which we granted because of the public importance of the questions presented. City of Cleveland v. Hope Natural Gas Co., 319 U.S. 735, 63 S.Ct. 1165.

Hope is a West Virginia corporation organized in 1898. It is a wholly owned subsidiary of Standard Oil Co. (N.J.). Since the date of its organization, it has been in the business of producing, purchasing and marketing natural gas in that state. FN1 It sells some of that gas to local consumers in West Virginia. But the great bulk of it goes to five customer companies which receive it at the West Virginia line and distribute it in Ohio and in Pennsylvania. FN2 In July, 1938, the cities of Cleveland and Akron filed complaints with the Commission charging that the rates collected by Hope from East Ohio Gas Co. (an affiliate of Hope which distributes gas in Ohio) were excessive and unreasonable. Later in 1938 the Commission on its own motion instituted an investigation to determine the reasonableness of all of Hope's interstate rates. In March ***595** 1939 the Public Utility Commission of Pennsylvania filed a complaint with the Commission charging that the rates collected by Hope from Peoples Natural Gas Co. (an affiliate of Hope distributing gas in Pennsylvania) and two non-affiliated companies were unreasonable. The City of Cleveland asked that the challenged rates be declared unlawful and that just and reasonable rates be determined from June 30, 1939 to the date of the Commission's order. The latter finding was requested in aid of state regulation and to afford the Public Utilities Commission of Ohio a proper basic for disposition of a fund collected by East Ohio under bond from Ohio consumers since June 30, 1939. The cases were consolidated and hearings were held.

FN1 Hope produces about one-third of its annual gas requirements and purchases the rest under some 300 contracts.

FN2 These five companies are the East Ohio Gas Co., the Peoples Natural Gas Co., the

River Gas Co., the Fayette County Gas Co., and the Manufacturers Light & Heat Co. The first three of these companies are, like Hope, subsidiaries of Standard Oil Co. (N.J.). East Ohio and River distribute gas in Ohio, the other three in Pennsylvania. Hope's approximate sales in m.c.f. for 1940 may be classified as follows:

Local West Virginia. sales.	11,000,000
East Ohio.	40,000,000
Peoples.	10,000,000
River.	400,000
Fayette.	860,000
Manufacturers.	2,000,000

Local West Virginia

Hope's natural gas is processed by Hope Construction & Refining Co., an affiliate, for the extraction of gasoline and butane. Domestic Coke Corp., another affiliate, sells coke-oven gas to Hope for boiler fuel.

On May 26, 1942, the Commission entered its order and made its findings. Its order required Hope to decrease its future interstate rates so as to reflect a reduction, on an annual basis of not less than $3,609,857 in operating revenues. And it established 'just and reasonable' average rates per m.c.f. for each of the five customer companies. [FN3] In response to the prayer of the City of Cleveland the Commission also made findings as to the lawfulness of past rates, although concededly it had no authority under the Act to fix past rates or to award reparations. 44 P.U.R.,U.S., at page 34. It found that the rates collected by Hope from East Ohio were unjust, unreasonable, excessive and therefore unlawful, by $830,892 during 1939, $3,219,551 during 1940, and $2,815,789 on an annual basis since 1940. It further found that just, reasonable, and lawful rates for gas sold by Hope to East Ohio for resale for ultimate public consumption were those required ***596** to produce $11,528,608 for 1939, $11,507,185 for 1940 and $11.910,947 annually since 1940.

FN3 These required minimum reductions of 7¢ per m.c.f. from the 36.5¢ and 35.5¢ rates previously charged East Ohio and Peoples, respectively, and 3¢ per m.c.f. from the 31.5¢ rate previously charged Fayette and Manufacturers.

The Commission established an interstate rate base of $33,712,526 which, it found, represented the 'actual legitimate cost' of the company's interstate property less depletion and depreciation and plus unoperated acreage, working capital and future net capital additions. The Commission, beginning with book cost, made ****285** certain adjustments not necessary to relate here and found the 'actual legitimate cost' of the plant in interstate service to be $51,957,416, as of December 31, 1940. It deducted accrued depletion and depreciation, which it found to be $22,328,016 on an 'economic-service-life' basis. And it added $1,392,021 for future net capital additions, $566,105 for useful unoperated acreage, and $2,125,000 for working capital. It used 1940 as a test year to estimate future revenues and expenses. It allowed over $16,000,000 as annual operating expenses-about $1,300,000 for taxes, $1,460,000 for depletion and depreciation, $600,000 for exploration and development costs, $8,500,000 for gas purchased. The Commission allowed a net increase of $421,160 over 1940 operating expenses, which amount was to take care of future increase in wages, in West Virginia property taxes, and in exploration and development costs. The total amount of deductions allowed from interstate revenues was $13,495,584.

Hope introduced evidence from which it estimated reproduction cost of the property at $97,000,000. It also presented a so-called trended 'original cost' estimate which exceeded $105,000,000. The latter was designed 'to indicate what the original cost of the property would have been if 1938 material and labor prices had prevailed throughout the whole period of the piece-meal construction of the company's property since 1898.' 44 P.U.R.,N.S., at pages 8, 9. Hope estimated by the 'percent condition' method accrued depreciation at about 35% of ***597** reproduction cost new. On that basis Hope contended for a rate base of $66,000,000. The Commission refused to place any reliance on reproduction cost new, saying that it was 'not predicated upon facts' and was 'too conjectural and illusory to be given any weight in these proceedings.' Id., 44 P.U.R.,U.S., at page 8. It likewise refused to give any 'probative value' to trended 'original cost' since it was 'not founded in fact' but was 'basically erroneous' and produced 'irrational results.' Id., 44 P.U.R., N.S., at page 9. In determining the amount of accrued depletion and depreciation the Commission, following Lindheimer v. Illinois Bell

Telephone Co., 292 U.S. 151, 167-169, 54 S.Ct. 658, 664-666, 78 L.Ed. 1182; Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 592, 593, 62 S.Ct. 736, 745, 746, 86 L.Ed. 1037, based its computation on 'actual legitimate cost'. It found that Hope during the years when its business was not under regulation did not observe 'sound depreciation and depletion practices' but 'actually accumulated an excessive reserve' FN4 of about $46,000,000. Id., 44 P.U.R.,N.S., at page 18. One member of the Commission thought that the entire amount of the reserve should be deducted from 'actual legitimate cost' in determining the rate base. FN5 The majority of the ***598** Commission concluded, however, that where, as here, a business is brought under regulation for the first time and where incorrect depreciation and depletion practices have prevailed, the deduction of the reserve requirement (actual existing depreciation and depletion) rather than the excessive reserve should be made so as to ****286** lay 'a sound basis for future regulation and control of rates.' Id., 44 P.U.R.,N.S., at page 18. As we have pointed out, it determined accrued depletion and depreciation to be $22,328,016; and it allowed approximately $1,460,000 as the annual operating expense for depletion and depreciation. FN6

FN4 The book reserve for interstate plant amounted at the end of 1938 to about $18,000,000 more than the amount determined by the Commission as the proper reserve requirement. The Commission also noted that 'twice in the past the company has transferred amounts aggregating $7,500,000 from the depreciation and depletion reserve to surplus. When these latter adjustments are taken into account, the excess becomes $25,500,000, which has been exacted from the ratepayers over and above the amount required to cover the consumption of property in the service rendered and thus to keep the investment unimpaired.' 44 P.U.R.,N.S., at page 22.

FN5 That contention was based on the fact that 'every single dollar in the depreciation and depletion reserves' was taken 'from gross operating revenues whose only source was the amounts charged customers in the past for natural gas. It is, therefore, a fact that the depreciation and depletion reserves have been contributed by the customers and do not represent any investment by Hope.' Id., 44 P.U.R.,N.S., at page 40. And see Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 424, 425, 29 S.Ct. 357, 361, 362, 53 L.Ed. 577; 2 Bonbright, Valuation of Property (1937), p. 1139.

FN6 The Commission noted that the case was 'free from the usual complexities involved in the estimate of gas reserves because the geologists for the company and the Commission presented estimates of the remaining recoverable gas reserves which were about one per cent apart.' 44 P.U.R.,N.S., at pages 19, 20.

The Commission utilized the 'straight-line-basis' for determining the depreciation and depletion reserve requirements. It used estimates of the average service lives of the property by classes based in part on an inspection of the physical condition of the property. And studies were made of Hope's retirement experience and maintenance policies over the years. The average service lives of the various classes of property were converted into depreciation rates and then applied to the cost of the property to ascertain the portion of the cost which had expired in rendering the service.

The record in the present case shows that Hope is on the lookout for new sources of supply of natural gas and is contemplating an extension of its pipe line into Louisiana for that purpose. The Commission recognized in fixing the rates of depreciation that much material may be used again when various present sources of gas supply are exhausted, thus giving that property more than scrap value at the end of its present use.

Hope's estimate of original cost was about $69,735,000-approximately $17,000,000 more than the amount found by the Commission. The item of $17,000,000 was made up largely of expenditures which prior to December 31, 1938, were charged to operating expenses. Chief among those expenditures was some $12,600,000 expended ***599** in well-drilling prior to 1923. Most of that sum was expended by Hope for labor, use of drilling-rigs, hauling, and similar costs of well-drilling. Prior to 1923 Hope followed the general practice of the natural gas industry and charged the cost of drilling wells to operating expenses. Hope continued that practice until the Public Service Commission of West Virginia in 1923 required it to capitalize such expenditures, as does the Commission under its present Uniform System of Accounts. FN7 The Commission refused to add such items to the rate base stating that 'No greater injustice to consumers could be done than to allow items as operating expenses and at a later date include them in the rate base, thereby placing multiple charges upon the consumers.' Id., 44 P.U.R.,N.S., at page 12. For the same reason the Commission excluded from the rate base about $1,600,000 of expenditures on properties which Hope acquired from other utilities, the latter having charged those payments to operating expenses. The Commission disallowed certain other overhead items amounting to over $3,000,000 which also had been previously charged to operating expenses. And it refused to add some $632,000 as interest during construction since no interest was in fact paid.

FN7 See Uniform System of Accounts prescribed for Natural Gas Companies effective January 1, 1940, Account No. 332.1.

Hope contended that it should be allowed a return of not less than 8%. The Commission found that an 8% return would be unreasonable but that 6 1/2% was a fair rate of return. That rate of return, applied to the rate base of $33,712,526, would produce $2,191,314 annually, as compared with the present income of not less than $5,801,171.

The Circuit Court of Appeals set aside the order of the Commission for the following reasons. (1) It held that the rate base should reflect the 'present fair value' of the ***600** property, that the Commission in determining the 'value' should have considered reproduction cost and trended original cost, and that 'actual legitimate cost' (prudent investment) was not the proper measure of 'fair value' where price levels had changed since the investment. (2) It concluded that the well-drilling costs and overhead items in the amount of some $17,000,000 should have been included in the rate base. (3) It held that accrued depletion and depreciation and the annual allowance for that expense should be computed on the basis of 'present fair value' of the property not on the basis of 'actual legitimate cost'.

****287** The Circuit Court of Appeals also held that the Commission had no power to make findings as to past rates in aid of state regulation. But it concluded that those findings were proper as a step in the process of fixing future rates. Viewed in that light, however, the findings were deemed to be invalidated by the same errors which vitiated the findings on which the rate order was based.

Order Reducing Rates. Congress has provided in s 4(a) of the Natural Gas Act that all natural gas rates subject to the jurisdiction of the Commission 'shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.' Sec. 5(a) gives the Commission the power, after hearing, to determine the 'just and reasonable rate' to be thereafter observed and to fix the rate by order. Sec. 5(a) also empowers the Commission to order a 'decrease where existing rates are unjust * * * unlawful, or are not the lowest reasonable rates.' And Congress has provided in s 19(b) that on review of these rate orders the 'finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive.' Congress, however, has provided no formula by which the 'just and reasonable' rate is to be determined. It has not filled in the ***601** details of the general prescription [FN8] of s 4(a) and s 5(a). It has not expressed in a specific rule the fixed principle of 'just and reasonable'.

FN8. Sec. 6 of the Act comes the closest to supplying any definite criteria for rate making. It provides in subsection (a) that, 'The Commission may investigate the ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.' Subsection (b) provides that every natural-gas company on request shall file with the Commission a statement of the 'original cost' of its property and shall keep the Commission informed regarding the 'cost' of all additions, etc.

[1] [2] When we sustained the constitutionality of the Natural Gas Act in the Natural Gas Pipeline Co. case, we stated that the 'authority of Congress to regulate the prices of commodities in interstate commerce is at least as great under the Fifth Amendment as is that of the states under the Fourteenth to regulate the prices of commodities in intrastate commerce.' 315 U.S. at page 582, 62 S.Ct. at page 741, 86 L.Ed. 1037. Rate-making is indeed but one species of price-fixing. Munn v. Illinois, 94 U.S. 113, 134, 24 L.Ed. 77. The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. Block v. Hirsh, 256 U.S. 135, 155-157, 41 S.Ct. 458, 459, 460, 65 L.Ed. 865, 16 A.L.R. 165; Nebbia v. New York, 291 U.S. 502, 523-539, 54 S.Ct. 505, 509-517, 78 L.Ed. 940, 89 A.L.R. 1469, and cases cited. It does, however, indicate that 'fair value' is the end product of the process of rate-making not the starting point as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon 'fair value' when the value of the going enterprise depends on earnings under whatever rates may be anticipated. [FN9]

FN9 We recently stated that the meaning of the word 'value' is to be gathered 'from the purpose for which a valuation is being made. Thus the question in a valuation for rate making is how much a utility will be allowed to earn. The basic question in a valuation for reorganization purposes is how much the enterprise in all probability can earn.' Institutional Investors v. Chicago, M., St. P. & P.R. Co., 318 U.S. 523, 540, 63 S.Ct. 727, 738.

***602** [3] [4] [5] [6] [7] We held in Federal Power Commission v. Natural Gas Pipeline Co., supra, that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. And when the Commission's order is challenged in the courts, the question is whether that order 'viewed in its entirety' meets the requirements of the Act. Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. Cf. ****288**Los Angeles Gas & Electric Corp. v. Railroad Commission, 289 U.S. 287, 304, 305, 314, 53 S.Ct. 637, 643, 644, 647, 77 L.Ed. 1180; West Ohio Gas Co. v. Public Utilities Commission (No. 1), 294 U.S. 63, 70, 55 S.Ct. 316, 320, 79 L.Ed. 761; West v. Chesapeake & Potomac Tel. Co., 295 U.S. 662, 692, 693, 55 S.Ct. 894, 906, 907, 79 L.Ed. 1640 (dissenting opinion). It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the Commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Cf. Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 29 S.Ct. 357, 53 L.Ed. 577; Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at pages 164, 169, 54 S.Ct. at pages 663, 665, 78 L.Ed. 1182; Railroad Commission v. Pacific Gas & E. Co., 302 U.S. 388, 401, 58 S.Ct. 334, 341, 82 L.Ed. 319.

***603** [8] [9] The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745, 86 L.Ed. 1037. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346, 12 S.Ct. 400, 402, 36 L.Ed. 176. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. See State of Missouri ex rel. South-western Bell Tel. Co. v. Public Service Commission, 262 U.S. 276, 291, 43 S.Ct. 544, 547, 67 L.Ed. 981, 31 A.L.R. 807 (Mr. Justice Brandeis concurring). The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint.

We have already noted that Hope is a wholly owned subsidiary of the Standard Oil Co. (N.J.). It has no securities outstanding except stock. All of that stock has been owned by Standard since 1908. The par amount presently outstanding is approximately $28,000,000 as compared with the rate base of $33,712,526 established by ***604** the Commission. Of the total outstanding stock $11,000,000 was issued in stock dividends. The balance, or about $17,000,000, was issued for cash or other assets. During the four decades of its operations Hope has paid over $97,000,000 in cash dividends. It had, moreover, accumulated by 1940 an earned surplus of about $8,000,000. It had thus earned the total investment in the company nearly seven times. Down to 1940 it earned over 20% per year on the average annual amount of its capital stock issued for cash or other assets. On an average invested capital of some $23,000,000 Hope's average earnings have been about 12% a year. And during this period it had accumulated in addition reserves for depletion and depreciation of about $46,000,000. Furthermore, during 1939, 1940 and 1941, Hope paid dividends of 10% on its stock. And in the year 1942, during about half of which the lower rates were in effect, it paid dividends of 7 1/2%. From 1939-1942 its earned surplus increased from $5,250,000 to about $13,700,000, i.e., to almost half the par value of its outstanding stock.

As we have noted, the Commission fixed a rate of return which permits Hope to earn $2,191,314 annually. In determining that amount it stressed the importance of maintaining the financial integrity of the ****289** company. It considered the financial history of Hope and a vast array of data bearing on the natural gas industry, related businesses, and general economic conditions. It noted that the yields on better issues of bonds of natural gas companies sold in the last few years were 'close to 3 per cent', 44 P.U.R.,N.S., at page 33. It stated that the company was a 'seasoned enterprise whose risks have been minimized' by adequate provisions for depletion and depreciation (past and present) with 'concurrent high profits', by 'protected established markets, through affiliated distribution companies, in populous and industralized areas', and by a supply of gas locally to meet all requirements,***605** 'except on certain peak days in the winter, which it is feasible to supplement in the future with gas from other sources.' Id., 44 P.U.R.,N.S., at page 33. The Commission concluded, 'The company's efficient management, established markets, financial record, affiliations, and its prospective business place it in a strong position to attract capital upon favorable terms when it is required.' Id., 44 P.U.R.,N.S., at page 33.

[10] [11] [12] In view of these various considerations we cannot say that an annual return of $2,191,314 is not 'just and reasonable' within the meaning of the Act. Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so-called 'fair value' rate base. In that connection it will be recalled that Hope contended for a rate base of $66,000,000 computed on reproduction cost new. The Commission points out that if that rate base were accepted, Hope's average rate of return for the four-year period from 1937-1940 would amount to 3.27%. During that period Hope earned an annual average return of about 9% on the average investment. It asked for no rate increases. Its properties were well maintained and operated. As the Commission says such a modest rate of 3.27% suggests an 'inflation of the base on which the rate has been computed.' Dayton Power & Light Co. v. Public Utilities Commission, 292 U.S. 290, 312, 54 S.Ct. 647, 657, 78 L.Ed. 1267. Cf. Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at page 164, 54 S.Ct. at page 663, 78 L.Ed. 1182. The incongruity between the actual operations and the return computed on the basis of reproduction cost suggests that the Commission was wholly justified in rejecting the latter as the measure of the rate base.

In view of this disposition of the controversy we need not stop to inquire whether the failure of the Commission to add the $17,000,000 of well-drilling and other costs to ***606** the rate base was consistent with the prudent investment theory as developed and applied in particular cases.

[13] [14] [15] Only a word need be added respecting depletion and depreciation. We held in the Natural Gas Pipeline Co. case that there was no constitutional requirement 'that the owner who embarks in a wasting-asset business of limited life shall receive at the end more than he has put into it.' 315 U.S. at page 593, 62 S.C. at page 746, 86 L.Ed. 1037. The Circuit Court of Appeals did not think that that rule was applicable here because Hope was a utility required to continue its service to the public and not scheduled to end its business on a day certain as was stipulated to be true of the Natural Gas Pipeline Co. But that distinction is quite immaterial. The ultimate exhaustion of the supply is inevitable in the case of all natural gas companies. Moreover, this Court recognized in Lindheimer v. Illinois Bell Tel. Co., supra, the propriety of basing annual depreciation on cost. [FN10] By such a procedure the ****290** utility is made whole and the integrity of its investment maintained. [FN11] No more is required. [FN12] We cannot approve the contrary holding ***607** of United Railways & Electric Co. v. West, 280 U.S. 234, 253, 254, 50 S.Ct. 123, 126, 127, 74 L.Ed. 390. Since there are no constitutional requirements more exacting than the standards of the Act, a rate order which conforms to the latter does not run afoul of the former.

FN10 Chief Justice Hughes said in that case (292 U.S. at pages 168, 169, 54 S.Ct. at page 665, 78 L.Ed. 1182): 'If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.'

FN11 See Mr. Justice Brandeis (dissenting) in United Railways & Electric Co. v. West, 280 U.S. 234, 259-288, 50 S.Ct. 123, 128-138, 74 L.Ed. 390, for an extended analysis of the problem.

FN12 It should be noted that the Act provides no specific rule governing depletion and depreciation. Sec. 9(a) merely states that the

> Commission 'may from time to time ascertain and determine, and by order fix, the proper and adequate rates of depreciation and amortization of the several classes of property of each natural-gas company used or useful in the production, transportation, or sale of natural gas.'

The Position of West Virginia. The State of West Virginia, as well as its Public Service Commission, intervened in the proceedings before the Commission and participated in the hearings before it. They have also filed a brief amicus curiae here and have participated in the argument at the bar. Their contention is that the result achieved by the rate order 'brings consequences which are unjust to West Virginia and its citizens' and which 'unfairly depress the value of gas, gas lands and gas leaseholds, unduly restrict development of their natural resources, and arbitrarily transfer their properties to the residents of other states without just compensation therefor.'

West Virginia points out that the Hope Natural Gas Co. holds a large number of leases on both producing and unoperated properties. The owner or grantor receives from the operator or grantee delay rentals as compensation for postponed drilling. When a producing well is successfully brought in, the gas lease customarily continues indefinitely for the life of the field. In that case the operator pays a stipulated gas-well rental or in some cases a gas royalty equivalent to one-eighth of the gas marketed. [FN13] Both the owner and operator have valuable property interests in the gas which are separately taxable under West Virginia law. The contention is that the reversionary interests in the leaseholds should be represented in the rate proceedings since it is their gas which is being sold in interstate ***608** commerce. It is argued, moreover, that the owners of the reversionary interests should have the benefit of the 'discovery value' of the gas leaseholds, not the interstate consumers. Furthermore, West Virginia contends that the Commission in fixing a rate for natural gas produced in that State should consider the effect of the rate order on the economy of West Virginia. It is pointed out that gas is a wasting asset with a rapidly diminishing supply. As a result West Virginia's gas deposits are becoming increasingly valuable. Nevertheless the rate fixed by the Commission reduces that value. And that reduction, it is said, has severe repercussions on the economy of the State. It is argued in the first place that as a result of this rate reduction Hope's West Virginia property taxes may be decreased in view of the relevance which earnings have under West Virginia law in the assessment of property for tax purposes. [FN14] Secondly, it is pointed out that West Virginia has a production tax [FN15] on the 'value' of the gas exported from the State. And we are told that for purposes of that tax 'value' becomes under West Virginia law 'practically the substantial equivalent of market value.' Thus West Virginia argues that undervaluation of Hope's gas leaseholds will cost the State many thousands of dollars in taxes. The effect, it is urged, is to impair West Virginia's tax structure for the benefit of Ohio and Pennsylvania consumers. West Virginia emphasizes, moreover, its deep interest in the conservation of its natural resources including its natural gas. It says that a reduction of the value of these leasehold values will jeopardize these conservation policies in three respects: (1) ****291** exploratory development of new fields will be discouraged; (2) abandonment of lowyield high-cost marginal wells will be hastened; and (3) secondary recovery of oil will be hampered. ***609** Furthermore, West Virginia contends that the reduced valuation will harm one of the great industries of the State and that harm to that industry must inevitably affect the welfare of the citizens of the State. It is also pointed out that West Virginia has a large interest in coal and oil as well as in gas and that these forms of fuel are competitive. When the price of gas is materially cheapened, consumers turn to that fuel in preference to the others. As a result this lowering of the price of natural gas will have the effect of depreciating the price of West Virginia coal and oil.

> FN13 See Simonton, The Nature of the Interest of the Grantee Under an Oil and Gas Lease (1918), 25 W.Va.L.Quar. 295.

> FN14 West Penn Power Co. v. Board of Review, 112 W.Va. 442, 164 S.E. 862.

> FN15 W.Va.Rev.Code of 1943, ch. 11. Art. 13, ss 2a, 3a.

West Virginia insists that in neglecting this aspect of the problem the Commission failed to perform the function which Congress entrusted to it and that the case should be remanded to the Commission for a modification of its order. [FN16]

> FN16 West Virginia suggests as a possible solution (1) that a 'going concern value' of the company's tangible assets be included in the rate base and (2) that the fair market value of gas delivered to customers be added to the outlay for operating expenses and taxes.

We have considered these contentions at length in view of the earnestness with which they have been urged upon us. We have searched the legislative history of the Natural

Gas Act for any indication that Congress entrusted to the Commission the various considerations which West Virginia has advanced here. And our conclusion is that Congress did not.

[16] [17] We pointed out in Illinois Natural Gas Co. v. Central Illinois Public Service Co., 314 U.S. 498, 506, 62 S.Ct. 384, 387, 86 L.Ed. 371, that the purpose of the Natural Gas Act was to provide, 'through the exercise of the national power over interstate commerce, an agency for regulating the wholesale distribution to public service companies of natural gas moving interstate, which this Court had declared to be interstate commerce not subject to certain types of state regulation.' As stated in the House Report the 'basic purpose' of this legislation was 'to occupy' the field in which such cases as ***610**State of Missouri v. Kansas Natural Gas Co., 265 U.S. 298, 44 S.Ct. 544, 68 L.Ed. 1027, and Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83, 47 S.Ct. 294, 71 L.Ed. 549, had held the States might not act. H.Rep. No. 709, 75th Cong., 1st Sess., p. 2. In accomplishing that purpose the bill was designed to take 'no authority from State commissions' and was 'so drawn as to complement and in no manner usurp State regulatory authority.' Id., p. 2. And the Federal Power Commission was given no authority over the 'production or gathering of natural gas.' s 1(b).

[18] The primary aim of this legislation was to protect consumers against exploitation at the lands of natural gas companies. Due to the hiatus in regulation which resulted from the Kansas Natural Gas Co. case and related decisions state commissions found it difficult or impossible to discover what it cost interstate pipe-line companies to deliver gas within the consuming states; and thus they were thwarted in local regulation. H.Rep., No. 709, supra, p. 3. Moreover, the investigations of the Federal Trade Commission had disclosed that the majority of the pipe-line mileage in the country used to transport natural gas, together with an increasing percentage of the natural gas supply for pipe-line transportation, had been acquired by a handful of holding companies. FN17 State commissions, independent producers, and communities having or seeking the service were growing quite helpless against these combinations. FN18 These were the types of problems with which those participating in the hearings were pre-occupied. FN19 Congress addressed itself to those specific evils.

FN17 S.Doc. 92, Pt. 84-A, ch. XII, Final Report, Federal Trade Commission to the Senate pursuant to S.Res.No. 83, 70th Cong., 1st Sess.

FN18 S.Doc. 92, Pt. 84-A, chs. XII, XIII, op. cit., supra, note 17.

FN19 See Hearings on H.R. 11662, Subcommittee of House Committee on Interstate & Foreign Commerce, 74th Cong., 2d Sess.; Hearings on H.R. 4008, House Committee on Interstate & Foreign Commerce, 75th Cong., 1st Sess.

611** The Federal Power Commission was given*292** broad powers of regulation. The fixing of 'just and reasonable' rates (s 4) with the powers attendant thereto FN20 was the heart of the new regulatory system. Moreover, the Commission was given certain authority by s 7(a), on a finding that the action was necessary or desirable 'in the public interest,' to require natural gas companies to extend or improve their transportation facilities and to sell gas to any authorized local distributor. By s 7(b) it was given control over the abandonment of facilities or of service. And by s 7(c), as originally enacted, no natural gas company could undertake the construction or extension of any facilities for the transportation of natural gas to a market in which natural gas was already being served by another company, or sell any natural gas in such a market, without obtaining a certificate of public convenience and necessity from the Commission. In passing on such applications for certificates of convenience and necessity the Commission was told by s 7(c), as originally enacted, that it was 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' The latter provision was deleted from s 7(c) when that subsection was amended by the Act of February 7, 1942, 56 Stat. 83. By that amendment limited grandfather rights were granted companies desiring to extend their facilities and services over the routes or within the area which they were already serving. Moreover, s 7(c) was broadened so as to require certificates***612** of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but in other situations as well.

FN20 The power to investigate and ascertain the 'actual legitimate cost' of property (s 6), the requirement as to books and records (s 8), control over rates of depreciation (s 9), the requirements for periodic and special reports (s 10), the broad powers of investigation (s 14) are among the chief powers supporting the rate making function.

[19] These provisions were plainly designed to protect the consumer interests against exploitation at the hands of private natural gas companies. When it comes to cases of abandonment or of extensions of facilities or service, we may assume that, apart from the express exemptions FN21 contained in s 7, considerations of conservation are material to the issuance of certificates of public convenience and necessity. But the Commission was not asked here for a certificate of public convenience and necessity under s 7 for any proposed construction or extension. It was faced with a determination of the amount which a private operator should be allowed to earn from the sale of natural gas across state lines through an established distribution system. Secs. 4 and 5, not s 7, provide the standards for that determination. We cannot find in the words of the Act or in its history the slightest intimation or suggestion that the exploitation of consumers by private operators through the maintenance of high rates should be allowed to continue provided the producing states obtain indirect benefits from it. That apparently was the Commission's view of the matter, for the same arguments advanced here were presented to the Commission and not adopted by it.

> FN21 Apart from the grandfather clause contained in s 7(c), there is the provision of s 7(f) that a natural gas company may enlarge or extend its facilities with the 'service area' determined by the Commission without any further authorization.

We do not mean to suggest that Congress was unmindful of the interests of the producing states in their natural gas supplies when it drafted the Natural Gas Act. As we have said, the Act does not intrude on the domain traditionally reserved for control by state commissions; and the Federal Power Commission was given no authority over***613** 'the production or gathering of natural gas.' s 1(b). In addition, Congress recognized the legitimate interests of the States in the conservation of natural gas. By s 11 Congress instructed the Commission to make reports on compacts between two or more States dealing with the conservation, production and transportation of natural gas. FN22 The Commission was also ****293** directed to recommend further legislation appropriate or necessary to carry out any proposed compact and 'to aid in the conservation of natural-gas resources within the United States and in the orderly, equitable, and economic production, transportation, and distribution of natural gas.' s 11(a). Thus Congress was quite aware of the interests of the producing states in their natural gas supplies. FN23 But it left the protection of ***614** those interests to measures other than the maintenance of high rates to private companies. If the Commission is to be compelled to let the stockholders of natural gas companies have a feast so that the producing states may receive crumbs from that table, the present Act must be redesigned. Such a project raises questions of policy which go beyond our province.

> FN22 See P.L. 117, approved July 7, 1943, 57 Stat. 383 containing an 'Interstate Compact to Conserve Oil and Gas' between Oklahoma, Texas, New Mexico, Illinois, Colorado, and Kansas.

> FN23 As we have pointed out, s 7(c) was amended by the Act of February 7, 1942, 56 Stat. 83, so as to require certificates of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but to other situations as well. Considerations of conservation entered into the proposal to give the Act that broader scope. H.Rep.No. 1290, 77th Cong. 1st Sess., pp. 2, 3. And see Annual Report, Federal Power Commission (1940) pp. 79, 80; Baum, The Federal Power Commission and State Utility Regulation (1942), p. 261.

The bill amending s 7(c) originally contained a subsection (h) reading as follows: 'Nothing contained in this section shall be construed to affect the authority of a State within which natural gas is produced to authorize or require the construction or extension of facilities for the transportation and sale of such gas within such State: Provided, however, That the Commission, after a hearing upon complaint or upon its own motion, may by order forbid any intrastate construction or extension by any natural-gas company which it shall find will prevent such company from rendering adequate service to its customers in interstate or foreign commerce in territory already being served.' See Hearings on H.R. 5249, House Committee on Interstate & Foreign Commerce, 77th Cong., 1st Sess., pp. 7, 11, 21, 29, 32, 33. In explanation of its deletion the House Committee Report stated, pp. 4, 5: 'The increasingly important problems raised by the desire of several States to regulate the use of the natural gas produced therein in the interest of consumers within such States, as against the Federal power to regulate interstate commerce in the interest of both interstate and intrastate consumers, are deemed by the committee to warrant further intensive study and probably a more retailed and comprehensive plan for the handling thereof than that which would have been provided by the stricken subsection.'

[20] It is hardly necessary to add that a limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state either to safeguard its tax revenues from that industry FN24 or to protect the interests of those who sell their gas to the interstate operator. FN25 The return which ****294** the Commission***615** allowed was the net return after all such charges.

FN24 We have noted that in the annual operating expenses of some $16,000.000 the Commission included West Virginia and federal taxes. And in the net increase of $421,160 over 1940 operating expenses allowed by the Commission was some $80,000 for increased West Virginia property taxes. The adequacy of these amounts has not been challenged here.

FN25 The Commission included in the aggregate annual operating expenses which it allowed some $8,500,000 for gas purchased. It also allowed about $1,400,000 for natural gas production and about $600,000 for exploration and development.

It is suggested, however, that the Commission in ascertaining the cost of Hope's natural gas production plant proceeded contrary to s 1(b) which provides that the Act shall not apply to 'the production or gathering of natural gas'. But such valuation, like the provisions for operating expenses, is essential to the rate-making function as customarily performed in this country. Cf. Smith, The Control of Power Rates in the United States and England (1932), 159 The Annals 101. Indeed s 14(b) of the Act gives the Commission the power to 'determine the propriety and reasonableness of the inclusion in operating expenses, capital, or surplus of all delay rentals or other forms of rental or compensation for unoperated lands and leases.'

It is suggested that the Commission has failed to perform its duty under the Act in that it has not allowed a return for gas production that will be enough to induce private enterprise to perform completely and efficiently its functions for the public. The Commission, however, was not oblivious of those matters. It considered them. It allowed, for example, delay rentals and exploration and development costs in operating expenses. FN26 No serious attempt has been made here to show that they are inadequate. We certainly cannot say that they are, unless we are to substitute our opinions for the expert judgment of the administrators to whom Congress entrusted the decision. Moreover, if in light of experience they turn out to be inadequate for development of new sources of supply, the doors of the Commission are open for increased allowances. This is not an order for all time. The Act contains machinery for obtaining rate adjustments. s 4.

FN26 See note 25, supra.

[21] [22] But it is said that the Commission placed too low a rate on gas for industrial purposes as compared with gas for domestic purposes and that industrial uses should be discouraged. It should be noted in the first place that the rates which the Commission has fixed are Hope's interstate wholesale rates to distributors not interstate rates to industrial users FN27 and domestic consumers. We hardly ***616** can assume, in view of the history of the Act and its provisions, that the resales intrastate by the customer companies which distribute the gas to ultimate consumers in Ohio and Pennsylvania are subject to the rate-making powers of the Commission. FN28 But in any event those rates are not in issue here. Moreover, we fail to find in the power to fix 'just and reasonable' rates the power to fix rates which will disallow or discourage resales for industrial use. The Committee Report stated that the Act provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions'. H.Rep.No.709, supra, p. 3. Yet if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine which has no express statutory sanction. The same would be true if we were to hold that the wasting-asset nature of the industry required the maintenance of the level of rates so that natural gas companies could make a greater profit on each unit of gas sold. Such theories of rate-making for this industry may or may not be desirable. The difficulty is that s 4(a) and s 5(a) contain only the conventional standards of rate-making for natural gas companies. FN29 The ***617** Act of February 7, 1942, by broadening s 7 gave the Commission some additional authority to deal with the conservation aspects of the problem. FN30 But s 4(a) and s 5(a) were not changed. If the standard****295** of 'just and reasonable' is to sanction the maintenance of high rates by a natural gas company because they restrict the use of natural gas for certain purposes, the Act must be further amended.

FN27 The Commission has expressed doubts over its power to fix rates on 'direct sales to industries' from interstate pipelines as distinguished from 'sales for resale to the industrial customers of distributing companies.' Annual Report, Federal Power Commission (1940), p. 11.

FN28. Sec. 1(b) of the Act provides: 'The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.' And see s 2(6), defining a 'natural-gas company', and H.Rep.No. 709, supra, pp. 2, 3.

FN29 The wasting-asset characteristic of the industry was recognized prior to the Act as requiring the inclusion of a depletion allowance among operating expenses. See Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 404, 405, 54 S.Ct. 763, 766, 767, 78 L.Ed. 1327, 91 A.L.R. 1403. But no such theory of rate-making for natural gas companies as is now suggested emerged from the cases arising during the earlier period of regulation.

FN30 The Commission has been alert to the problems of conservation in its administration of the Act. It has indeed suggested that it might be wise to restrict the use of natural gas 'by functions rather than by areas.' Annual Report (1940) p. 79.
The Commission stated in that connection that natural gas was particularly adapted to certain industrial uses. But it added that the general use of such gas 'under boilers for the production of steam' is 'under most circumstances of very questionable social economy.' Ibid.

[23] [24] It is finally suggested that the rates charged by Hope are discriminatory as against domestic users and in favor of industrial users. That charge is apparently based on s 4(b) of the Act which forbids natural gas companies from maintaining 'any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.' The power of the Commission to eliminate any such unreasonable differences or discriminations is plain. s 5(a). The Commission, however, made no findings under s 4(b). Its failure in that regard was not challenged in the petition to review. And it has not been raised or argued here by any party. Hence the problem of discrimination has no proper place in the present decision. It will be time enough to pass on that issue when it is presented to us. Congress has entrusted the administration of the Act to the Commission not to the courts. Apart from the requirements of judicial review it is not ***618** for us to advise the Commission how to discharge its functions.

Findings as to the Lawfulness of Past Rates. As we have noted, the Commission made certain findings as to the lawfulness of past rates which Hope had charged its interstate customers. Those findings were made on the complaint of the City of Cleveland and in aid of state regulation. It is conceded that under the Act the Commission has no power to make reparation orders. And its power to fix rates admittedly is limited to those 'to be thereafter observed and in force.' s 5(a). But the Commission maintains that it has the power to make findings as to the lawfulness of past rates even though it has no power to fix those rates. [FN31] However that may be, we do not think that these findings were reviewable under s 19(b) of the Act. That section gives any party 'aggrieved by an order' of the Commission a review 'of such order' in the circuit court of appeals for the circuit where the natural gas company is located or has its principal place of business or in the United States Court of Appeals for the District of Columbia. We do not think that the findings in question fall within that category.

FN31 The argument is that s 4(a) makes 'unlawful' the charging of any rate that is not just and reasonable. And s 14(a) gives the Commission power to investigate any matter 'which it may find necessary or proper in order to determine whether any person has violated' any provision of the Act. Moreover, s 5(b) gives the Commission power to investigate and determine the cost of production or transportation of natural gas in cases where it has 'no authority to establish a rate governing the transportation or sale of such natural gas.' And s 17(c) directs the Commission to 'make available to the several State commissions such information and reports as may be of assistance in State regulation of natural-gas companies.' For a discussion of these points by the Commission see 44 P.U.R.,N.S., at pages 34, 35.

[25] [26] The Court recently summarized the various types of administrative action or determination reviewable as orders under the Urgent Deficiencies Act of October 22, ***619** 1913, 28 U.S.C. ss 45, 47a, 28 U.S.C.A. ss 45, 47a, and kindred statutory provisions. Rochester Tel. Corp. v. United States, 307 U.S. 125, 59 S.Ct. 754, 83 L.Ed. 1147. It was there pointed out that where 'the order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action', it is not

reviewable. Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. The Court said, 'In view of traditional conceptions of federal judicial power, resort to the courts in these situations is either premature or wholly beyond their province.' ****296**Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. And see United States v. Los Angeles s.l.r. c/o., 273 U.S. 299, 309, 310, 47 S.Ct. 413, 414, 415, 71 L.Ed. 651; Shannahan v. United States, 303 U.S. 596, 58 S.Ct. 732, 82 L.Ed. 1039. These considerations are apposite here. The Commission has no authority to enforce these findings. They are 'the exercise solely of the function of investigation.' United States v. Los Angeles & S.L.R. Co., supra, 273 U.S. at page 310, 47 S.Ct. at page 414, 71 L.Ed. 651. They are only a preliminary, interim step towards possible future action-action not by the Commission but by wholly independent agencies. The outcome of those proceedings may turn on factors other than these findings. These findings may never result in the respondent feeling the pinch of administrative action.

Reversed.

Mr. Justice ROBERTS took no part in the consideration or decision of this case.

Opinion of Mr. Justice BLACK and Mr. Justice MURPHY.

We agree with the Court's opinion and would add nothing to what has been said but for what is patently a wholly gratuitous assertion as to Constitutional law in the dissent of Mr. Justice FRANKFURTER. We refer to the statement that 'Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra (134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970), may fairly be claimed.' That was the case in which a majority of this Court was finally induced to expand the meaning ***620** of 'due process' so as to give courts power to block efforts of the state and national governments to regulate economic affairs. The present case does not afford a proper occasion to discuss the soundness of that doctrine because, as stated in Mr. Justice FRANKFURTER'S dissent, 'That issue is not here in controversy.' The salutary practice whereby courts do not discuss issues in the abstract applies with peculiar force to Constitutional questions. Since, however, the dissent adverts to a highly controversial due process doctrine and implies its acceptance by Congress, we feel compelled to say that we do not understand that Congress voluntarily has acquiesced in a Constitutional principle of government that courts, rather than legislative bodies, possess final authority over regulation of economic affairs. Even this Court has not always fully embraced that principle, and we wish to repeat that we have never acquiesced in it, and do not now. See Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 599-601, 62 S.Ct. 736, 749, 750, 86 L.Ed. 1037.

Mr. Justice REED, dissenting.

This case involves the problem of rate making under the Natural Gas Act. Added importance arises from the obvious fact that the principles stated are generally applicable to all federal agencies which are entrusted with the determination of rates for utilities. Because my views differ somewhat from those of my brethren, it may be of some value to set them out in a summary form.

The Congress may fix utility rates in situations subject to federal control without regard to any standard except the constitutional standards of due process and for taking private property for public use without just compensation. Wilson v. New, 243 U.S. 332, 350, 37 S.Ct. 298, 302, 61 L.Ed. 755, L.R.A.1917E, 938, Ann.Cas.1918A, 1024. A Commission, however, does not have this freedom of action. Its powers are limited not only by the constitutional standards but also by the standards of the delegation. Here the standard added by the Natural Gas Act is that the rate be 'just ***621** and reasonable.' FN1 Section 6 FN2 ****297** throws additional light on the meaning of these words.

FN1 Natural Gas Act, s 4(a), 52 Stat. 821, 822, 15 U.S.C. s 717c(a), 15 U.S.C.A. s 717c(a).

FN2 52 Stat. 821, 824, 15 U.S.C. s 717e, 15 U.S.C.A. s 717e:

'(a) The Commission may investigate and ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.

'(b) Every natural-gas company upon request shall file with the Commission an inventory of all or any part of its property and a statement of the original cost thereof, and shall keep the Commission informed regarding the cost of all additions, betterments, extensions, and new construction.'

When the phrase was used by Congress to describe allowable rates, it had relation to something ascertainable. The rates were not left to the whim of the Commission. The rates fixed would produce an annual return and that annual return was to be compared with a theoretical just and reasonable return, all risks considered, on the fair value of the property used and useful in the public service at the time of the determination.

Such an abstract test is not precise. The agency charged with its determination has a wide range before it could properly be said by a court that the agency had disregarded statutory standards or had confiscated the property of the utility for public use. Cf. Chicago, M. & St. P.R. Co. v. Minnesota, 134 U.S. 418, 461-466, 10 S.Ct. 462, 702, 703-705, 33 L.Ed. 970, dissent. This is as Congress intends. Rates are left to an experienced agency particularly competent by training to appraise the amount required.

The decision as to a reasonable return had not been a source of great difficulty, for borrowers and lenders reached such agreements daily in a multitude of situations; and although the determination of fair value had been troublesome, its essentials had been worked out in fairness to investor and consumer by the time of the enactment***622** of this Act. Cf. Los Angeles G. & E. Corp. v. Railroad Comm., 289 U.S. 287, 304 et seq., 53 S.Ct. 637, 643 et seq., 77 L.Ed. 1180. The results were well known to Congress and had that body desired to depart from the traditional concepts of fair value and earnings, it would have stated its intention plainly. Helvering v. Griffiths, 318 U.S. 371, 63 S.Ct. 636.

It was already clear that when rates are in dispute, 'earnings produced by rates do not afford a standard for decision.' 289 U.S. at page 305, 53 S.Ct. at page 644, 77 L.Ed. 1180. Historical cost, prudent investment and reproduction cost [FN3] were all relevant factors in determining fair value. Indeed, disregarding the pioneer investor's risk, if prudent investment and reproduction cost were not distorted by changes in price levels or technology, each of them would produce the same result. The realization from the risk of an investment in a speculative field, such as natural gas utilities, should be reflected in the present fair value. [FN4] The amount of evidence to be admitted on any point was of course in the agency's reasonable discretion, and it was free to give its own weight to these or other factors and to determine from all the evidence its own judgment as to the necessary rates.

> FN3 'Reproduction cost' has been variously defined, but for rate making purposes the most useful sense seems to be, the minimum amount necessary to create at the time of the inquiry a modern plant capable of rendering equivalent service. See I Bonbright, Valuation of Property (1937) 152. Reproduction cost as the cost of building a replica of an obsolescent plant is not of real significance.

'Prudent investment' is not defined by the Court. It may mean the sum originally put in the enterprise, either with or without additional amounts from excess earnings reinvested in the business.

> FN4 It is of no more than bookkeeping significance whether the Commission allows a rate of return commensurate with the risk of the original investment or the lower rate based on current risk and a capitalization reflecting the established earning power of a successful company and the probable cost of duplicating its services. Cf. American T. & T. Co. v. United States, 299 U.S. 232, 57 S.Ct. 170, 81 L.Ed. 142. But the latter is the traditional method.

***623** I agree with the Court in not imposing a rule of prudent investment alone in determining the rate base. This leaves the Commission free, as I understand it, to use any available evidence for its finding of fair value, including both prudent investment and the cost of installing at the present time an efficient system for furnishing the needed utility service.

My disagreement with the Court arises primarily from its view that it makes no ****298** difference how the Commission reached the rate fixed so long as the result is fair and reasonable. For me the statutory command to the Commission is more explicit. Entirely aside from the constitutional problem of whether the Congress could validly delegate its rate making power to the Commission, in toto and without standards, it did legislate in the light of the relation of fair and reasonable to fair value and reasonable return. The Commission must therefore make its findings in observance of that relationship.

The Federal Power Commission did not, as I construe their action, disregard its statutory duty. They heard the evidence relating to historical and reproduction cost and to the reasonable rate of return and they appraised its weight. The evidence of reproduction cost was rejected as unpersuasive, but from the other evidence they found a rate base, which is to me a determination of fair value. On that base the earnings allowed seem fair and reasonable. So far as the Commission went in appraising the property employed in the service, I find nothing in the result which indicates confiscation, unfairness or unreasonableness. Good administration of rate making agencies under this method would avoid undue delay and render revaluations unnecessary except after violent fluctuations of price levels. Rate making under this method has been subjected to criticism. But until Congress changes the standards for the agencies, these rate making bodies should continue the conventional theory of rate ***624** making. It will probably be simpler to improve present methods than to devise new ones.

But a major error, I think was committed in the disregard by the Commission of the investment in exploratory operations and other recognized capital costs. These were not considered by the Commission because they were charged to operating expenses by the company at a time when it was unregulated. Congress did not direct the Commission in rate making to deduct from the rate base capital investment which had been recovered during the unregulated period through excess earnings. In my view this part of the investment should no more have been disregarded in the rate base than any other capital investment which previously had been recovered and paid out in dividends or placed to surplus. Even if prudent investment throughout the life of the property is accepted as the formula for figuring the rate base, it seems to me illogical to throw out the admittedly prudent cost of part of the property because the earnings in the unregulated period had been sufficient to return the prudent cost to the investors over and above a reasonable return. What would the answer be under the theory of the Commission and the Court, if the only prudent investment in this utility had been the seventeen million capital charges which are now disallowed?

For the reasons heretofore stated, I should affirm the action of the Circuit Court of Appeals in returning the proceeding to the Commission for further consideration and should direct the Commission to accept the disallowed capital investment in determining the fair value for rate making purposes.

Mr. Justice FRANKFURTER, dissenting.
My brother JACKSON has analyzed with particularity the economic and social aspects of natural gas as well as ***625** the difficulties which led to the enactment of the Natural Gas Act, especially those arising out of the abortive attempts of States to regulate natural gas utilities. The Natural Gas Act of 1938 should receive application in the light of this analysis, and Mr. Justice JACKSON has, I believe, drawn relevant inferences regarding the duty of the Federal Power Commission in fixing natural gas rates. His exposition seems to me unanswered, and I shall say only a few words to emphasize my basic agreement with him.

For our society the needs that are met by public utilities are as truly public services as the traditional governmental functions of police and justice. They are not less so when these services are rendered by private enterprise under governmental regulation. Who ultimately determines the ways of regulation, is the decisive aspect in the public supervision of privately-owned utilities. Foreshadowed nearly sixty years ago, Railroad Commission Cases (Stone v. Farmers' Loan & Trust Co.), 116 U.S. 307, 331, 6 S.Ct. 334, 344, 388, 1191, 29 L.Ed. 636, it was decided more than fifty ****299** years ago that the final say under the Constitution lies with the judiciary and not the legislature. Chicago, etc., R. Co. v. Minnesota , 134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970.

While legal issues touching the proper distribution of governmental powers under the Constitution may always be raised, Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra, may fairly be claimed. But in any event that issue is not here in controversy. As pointed out in the opinions of my brethren, Congress has given only limited authority to the Federal Power Commission and made the exercise of that authority subject to judicial review. The Commission is authorized to fix rates chargeable for natural gas. But the rates that it can fix must be 'just and reasonable'. s 5 of the Natural Gas Act, 15 U.S.C. s 717d, 15 U.S.C.A. s 717d. Instead of making the Commission's rate determinations final, Congress***626** specifically provided for court review of such orders. To be sure, 'the finding of the Commission as to the facts, if supported by substantial evidence' was made 'conclusive', s 19 of the Act, 15 U.S.C. s 717r; 15 U.S.C.A. s 717r. But obedience of the requirement of Congress that rates be 'just and reasonable' is not an issue of fact of which the Commission's own determination is conclusive. Otherwise, there would be nothing for a court to review except questions of compliance with the procedural provisions of the Natural Gas Act. Congress might have seen fit so to cast its legislation. But it has not done so. It has committed to the administration of the Federal Power Commission the duty of applying standards of fair dealing and of reasonableness relevant to the purposes expressed by the Natural Gas Act. The requirement that rates must be 'just and reasonable' means just and reasonable in relation to appropriate standards. Otherwise Congress would have directed the Commission to fix such rates as in the judgment of the Commission are just and reasonable; it would not have also provided that such determinations by the Commission are subject to court review.

To what sources then are the Commission and the courts to go for ascertaining the standards relevant to the regulation of natural gas rates? It is at this point that Mr. Justice JACKSON'S analysis seems to me pertinent. There appear to be two alternatives. Either the fixing of natural gas rates must be left to the unguided discretion of the Commission so long as the rates it fixes do not reveal a glaringly had prophecy of the ability of a regulated utility to continue its service in the future. Or the Commission's rate orders must be founded on due consideration of all the elements of the public interest which the production and distribution of natural gas involve just because it is natural gas. These elements are reflected in the Natural Gas Act, if that Act be applied as an entirety. See, for ***627** instance, ss 4(a)(b)(c)(d), 6, and 11, 15 U.S.C. ss 717c(a)(b)(c)(d), 717e, and 717j, 15 U.S.C.A. ss 717c(a-d), 717e, 717j. Of course the statute is not concerned with abstract theories of ratemaking. But its very foundation is the 'public interest', and the public interest is a texture of multiple strands. It includes more than contemporary investors and contemporary consumers. The needs to be served are not restricted to immediacy, and social as well as economic costs must be counted.

It will not do to say that it must all be left to the skill of experts. Expertise is a rational process and a rational process implies expressed reasons for judgment. It will little advance the public interest to substitute for the hodge-podge of the rule in Smyth v. Ames, 169 U.S. 466, 18 S.Ct. 418, 42 L.Ed. 819, an encouragement of conscious obscurity or confusion in reaching a result, on the assumption that so long as the result appears harmless its basis is irrelevant. That may be an appropriate attitude when state action is challenged as unconstitutional. Cf. Driscoll v. Edison Light & Power Co., 307 U.S. 104, 59 S.Ct. 715, 83 L.Ed. 1134. But it is not to be assumed that it was the design of Congress to make the accommodation of the conflicting interests exposed in Mr. Justice JACKSON'S opinion the occasion for a blind clash of forces or a partial assessment of relevant factors, either before the Commission or here.

The objection to the Commission's action is not that the rates it granted were too low but that the range of its vision was too narrow. And since the issues before the Commission involved no less than the ****300** total public interest, the proceedings before it should not be judged by narrow conceptions of common law pleading. And so I conclude that the case should be returned to the Commission. In order to enable this Court to discharge its duty of reviewing the Commission's order, the Commission should set forth with explicitness the criteria by which it is guided ***628** in determining that rates are 'just and reasonable', and it should determine the public interest that is in its keeping in the perspective of the considerations set forth by Mr. Justice JACKSON.

By Mr. Justice JACKSON.

Certainly the theory of the court below that ties rate-making to the fair-value-reproduction-cost formula should be overruled as in conflict with Federal Power Commission v. Natural Gas Pipeline Co. [FN1] But the case should, I think, be the occasion for reconsideration of our rate-making doctrine as applied to natural gas and should be returned to the Commission for further consideration in the light thereof.

FN1 315 U.S. 575, 62 S.Ct. 736, 86 L.Ed. 1037.

The Commission appears to have understood the effect of the two opinions in the Pipeline case to be at least authority and perhaps direction to fix natural gas rates by exclusive application of the 'prudent investment' rate base theory. This has no warrant in the opinion of the Chief Justice for the Court, however, which released the Commission from subservience to 'any single formula or combination of formulas' provided its order, 'viewed in its entirety, produces no arbitrary result.' 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. The minority opinion I understood to advocate the 'prudent investment' theory as a sufficient guide in a natural gas case. The view was expressed in the court below that since this opinion was not expressly controverted it must have been approved. [FN2] I disclaim this imputed***629** approval with some particularity, because I attach importance at the very beginning of federal regulation of the natural gas industry to approaching it as the performance of economic functions, not as the performance of legalistic rituals.

FN2 Judge Dobie, dissenting below, pointed out that the majority opinion in the Pipeline case 'contains no express discussion of the Prudent Investment Theory' and that the concurring opinion contained a clear one, and said, 'It is difficult for me to believe that the majority of the Supreme Court, believing otherwise, would leave such a statement unchallenged.' (134 F.2d 287, 312.) The fact that two other Justices had as matter of record in our books long opposed the reproduction cost theory of rate bases and had commented favorably on the prudent investment theory may have influenced that conclusion. See opinion of Mr. Justice Frankfurter in Driscoll v. Edison Light & Power Co., 307 U.S. 104, 122, 59 S.Ct. 715, 724, 83 L.Ed. 1134, and my brief as Solicitor General in that case. It should be noted, however, that these statements were made, not in a natural gas case, but in an electric power case-a very important distinction, as I shall try to make plain.

I.

Solutions of these cases must consider eccentricities of the industry which gives rise to them and also to the Act of Congress by which they are governed.

The heart of this problem is the elusive, exhaustible, and irreplaceable nature of natural gas itself. Given sufficient money, we can produce any desired amount of railroad, bus, or steamship transportation, or communications facilities, or capacity for generation of electric energy, or for the manufacture of gas of a kind. In the service of such utilities one customer has little concern with the amount taken by another, one's waste will not deprive another, a volume of service and be created equal to demand, and today's demands will not exhaust or lessen capacity to serve tomorrow. But the wealth of Midas and the wit of man cannot produce or reproduce a natural gas field. We cannot even reproduce the gas, for our manufactured product has only about half the heating value per unit of nature's own. [FN3]

FN3 Natural gas from the Appalachian field averages about 1050 to 1150 B.T.U. content, while by-product manufactured gas is about 530 to 540. Moody's Manual of Public Utilities (1943) 1350; Youngberg, Natural Gas (1930) 7.

****301** Natural gas in some quantity is produced in twenty-four states. It is consumed in only thirty-five states, and is ***630** available only to about 7,600,000 consumers. [FN4] Its availability has been more localized than that of any other utility service because it has depended more on the caprice of nature.

FN4 Sen.Rep. No. 1162, 75th Cong., 1st Sess., 2.

The supply of the Hope Company is drawn from that old and rich and vanishing field that flanks the Appalachian mountains. Its center of production is Pennsylvania and West Virginia, with a fringe of lesser production in New York, Ohio, Kentucky, Tennessee, and the north end of Alabama. Oil was discovered in commercial quantities at a depth of only 69 1/2 feet near Titusville, Pennsylvania, in 1859. Its value then was about $16 per barrel. [FN5] The oil branch of the petroleum industry went forward at once, and with unprecedented speed. The area productive of oil and gas was roughed out by the drilling of over 19,000 'wildcat' wells, estimated to have cost over $222,000,000. Of these, over 18,000 or 94.9 per cent, were 'dry holes.' About five per cent, or 990 wells, made discoveries of commercial importance, 767 of them resulting chiefly in oil and 223 in gas only. [FN6] Prospecting for many years was a search for oil, and to strike gas was a misfortune. Waste during this period and even later is appalling. Gas was regarded as having no commercial value until about 1882, in which year the total yield was valued only at about $75,000. [FN7] Since then, contrary to oil, which has become cheaper gas in this field has pretty steadily advanced in price.

FN5 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 78.

FN6. Id. at 62-63.

FN7. Id. at 61.

While for many years natural gas had been distributed on a small scale for lighting, [FN8] its acceptance was slow, ***631** facilities for its utilization were primitive, and not until 1885 did it take on the appearance of a substantial industry. [FN9] Soon monopoly of production or markets developed. [FN10] To get gas from the mountain country, where it was largely found, to centers of population, where it was in demand, required very large investment. By ownership of such facilities a few corporate systems, each including several companies, controlled access to markets. Their purchases became the dominating factor in giving a market value to gas produced by many small operators. Hope is the market for over 300 such operators. By 1928 natural gas in the Appalachian field commanded an average price of 21.1 cents per m.c.f. at points of production and was bringing 45.7 cents at points of consumption. [FN11] The companies which controlled markets, however, did not rely on gas purchases alone. They acquired and held in fee or leasehold great acreage in territory proved by 'wildcat' drilling. These large marketing system companies as well as many small independent owners and operators have carried on the commercial development of proved territory. The development risks appear from the estimate that up to 1928, 312,318 proved area wells had been sunk in the Appalachian field of which 48,962, or 15.7 per cent, failed to produce oil or gas in commercial quantity. [FN12]

FN8 At Fredonia, New York, in 1821, natural gas was conveyed from a shallow well to some thirty people. The lighthouse at Barcelona Harbor, near what is now Westfield, New York, was at about that time and for many years afterward lighted by gas that issued from a crevice. Report on Utility Corporations by Federal Trade Commission, Sen.Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 8-9.

FN9 In that year Pennsylvania enacted 'An Act to provide for the incorporation and regulation of natural gas companies.' Penn.Laws 1885, No. 32, 15 P.S. s 1981 et seq.

FN10 See Steptoe and Hoffheimer's Memorandum for Governor Cornwell of West Virginia (1917) 25 West Virginia Law Quarterly 257; see also Report on Utility Corporations by

Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN11 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 73.

FN12. Id. at 63.

***632** With the source of supply thus tapped to serve centers of large demand, like Pittsburgh, Buffalo, Cleveland, Youngstown, Akron, and other industrial communities, the distribution of natural gas fast became big business. Its advantages as a ****302** fuel and its price commended it, and the business yielded a handsome return. All was merry and the goose hung high for consumers and gas companies alike until about the time of the first. World War. Almost unnoticed by the consuming public, the whole Appalachian field passed its peak of production and started to decline. Pennsylvania, which to 1928 had given off about 38 per cent of the natural gas from this field, had its peak in 1905; Ohio, which had produced 14 per cent, had its peak in 1915; and West Virginia, greatest producer of all, with 45 per cent to its credit, reached its peak in 1917. [FN13]

FN13. Id. at 64.

Western New York and Eastern Ohio, on the fringe of the field, had some production but relied heavily on imports from Pennsylvania and West Virginia. Pennsylvania, a producing and exporting state, was a heavy consumer and supplemented her production with imports from West Virginia. West Virginia was a consuming state, but the lion's share of her production was exported. Thus the interest of the states in the North Appalachian supply was in conflict.

Competition among localities to share in the failing supply and the helplessness of state and local authorities in the presence of state lines and corporate complexities is a part of the background of federal intervention in the industry. [FN14] West Virginia took the boldest measure. It legislated a priority in its entire production in favor of its own inhabitants. That was frustrated by an injunction***633** from this Court. [FN15] Throughout the region clashes in the courts and conflicting decisions evidenced public anxiety and confusion. It was held that the New York Public Service Commission did not have power to classify consumers and restrict their use of gas. [FN16] That Commission held that a company could not abandon a part of its territory and still serve the rest. [FN17] Some courts admonished the companies to take action to protect consumers. [FN18] Several courts held that companies, regardless of failing supply, must continue to take on customers, but such compulsory additions were finally held to be within the Public Service Commission's discretion. [FN19] There were attempts to throw up franchises and quit the service, and municipalities resorted to the courts with conflicting results. [FN20] Public service commissions of consuming states were handicapped, for they had no control of the supply. [FN21]

FN14 See Report on Utility Corporations by Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN15 Commonwealth of Pennsylvania v. West Virginia, 262 U.S. 553, 43 S.Ct. 658, 67 L.Ed. 1117, 32 A.L.R. 300. For conditions there which provoked this legislation, see 25 West Virginia Law Quarterly 257.

FN16 People ex rel. Pavilion Natural Gas Co. v. Public Service Commission, 188 App.Div. 36, 176 N.Y.S. 163.

FN17 Village of Falconer v. Pennsylvania Gas Company, 17 State Department Reports, N.Y., 407.

FN18 See, for example, Public Service Commission v. Iroquois Natural Gas Co., 108 Misc. 696, 178 N.Y.S. 24; Park Abbott Realty Co. v. Iroquois Natural Gas Co., 102 Misc. 266, 168 N.Y.S. 673; Public Service Commission v. Iroquois Natural Gas Co., 189 App.Div. 545, 179 N.Y.S. 230.

FN19 People ex rel. Pennsylvania Gas Co. v. Public Service Commission, 196 App.Div. 514, 189 N.Y.S. 478.

FN20 East Ohio Gas Co. v. Akron, 81 Ohio St. 33, 90 N.E. 40, 26 L.R.A., N.S., 92, 18 Ann.Cas. 332; Village of New-comerstown v. Consolidated Gas Co., 100 Ohio St. 494, 127 N.E. 414; Gress v. Village of Ft. Laramie, 100 Ohio St. 35, 125 N.E. 112, 8 A.L.R. 242; City of Jamestown v. Pennsylvania Gas Co., D.C., 263 F. 437; Id., D.C., 264 F. 1009. See, also, United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 308, 49 S.Ct. 150, 152, 73 L.Ed. 390.

FN21 The New York Public Service Commission said: ‘While the transportation of natural gas through pipe lines from one state to another state is interstate commerce * * *, Congress has not taken over the regulation of that particular industry. Indeed, it has expressly excepted it from the operation of the Interstate Commerce Commissions Law (Interstate Commerce Commissions Law, section 1). It is quite clear, therefore, that this Commission can not require a Pennsylvania corporation producing gas in Pennsylvania to transport it and deliver it in the State of New York, and that the Interstate Commerce Commission is likewise powerless. If there exists such a power, and it seems that there does, it is a power vested in Congress and by it not yet exercised. There is no available source of supply for the Crystal City Company at present except through purchasing from the Porter Gas Company. It is possible that this Commission might fix a price at which the Potter Gas Company should sell if it sold at all, but as the Commission can not require it to supply gas in the State of New York, the exercise of such a power to fix the price, if such power exists, would merely say, sell at this price or keep out of the State.' Lane v. Crystal City Gas Co., 8 New York Public Service Comm.Reports, Second District, 210, 212.

****303 *634** Shortages during World War I occasioned the first intervention in the natural gas industry by the Federal Government. Under Proclamation of President Wilson the United States Fuel Administrator took control, stopped extensions, classified consumers and established a priority for domestic over industrial use. FN22 After the war federal control was abandoned. Some cities once served with natural gas became dependent upon mixed gas of reduced heating value and relatively higher price. FN23

FN22 Proclamation by the President of September 16, 1918; Rules and Regulations of H. A. Garfield, Fuel Administrator, September 24, 1918.

FN23 For example, the Iroquois Gas Corporation which formerly served Buffalo, New York, with natural gas ranging from 1050 to 1150 b.t.u. per cu. ft., now mixes a by-product gas of between 530 and 540 b.t.u. in proportions to provide a mixed gas of about 900 b.t.u. per cu. ft. For space heating or water heating its charges range from 65 cents for the first m.c.f. per month to 55 cents for all above 25 m.c.f. per month. Moody's Manual of Public Utilities (1943) 1350.

Utilization of natural gas of highest social as well as economic return is domestic use for cooking and water ***635** heating, followed closely by use for space heating in homes. This is the true public utility aspect of the enterprise, and its preservation should be the first concern of regulation. Gas does the family cooking cheaper than any other fuel. FN24 But its advantages do not end with dollars and cents cost. It is delivered without interruption at the meter as needed and is paid for after it is used. No money is tied up in a supply, and no space is used for storage. It requires no handling, creates no dust, and leaves no ash. It responds to thermostatic control. It ignites easily and immediately develops its maximum heating capacity. These incidental advantages make domestic life more liveable.

FN24 The United States Fuel Administration made the following cooking value comparisons, based on tests made in the Department of Home Economics of Ohio State University:
Natural gas at 1.12 per M. is equivalent to coal at $6.50 per ton.
Natural gas at 2.00 per M. is equivalent to gasoline at 27¢ per gal.
Natural gas at 2.20 per M. is equivalent to electricity at 3¢ per k.w.h.
Natural gas at 2.40 per M. is equivalent to coal oil at 15¢ per gal.
Use and Conservation of Natural Gas, issued by U.S. Fuel Administration (1918) 5.

Industrial use is induced less by these qualities than by low cost in competition with other fuels. Of the gas exported from West Virginia by the Hope Company a very substantial part is used by industries. This wholesale use speeds exhaustion of supply and displaces other fuels. Coal miners and the coal industry, a large part of whose costs are wages, have complained of unfair competition from low-priced industrial gas produced with relatively little labor cost. FN25

FN25 See Brief on Behalf jof Legislation Imposing an Excise Tax on Natural Gas, submitted to N.R.A. by the United Mine Workers of America and the National Coal Association.

Gas rate structures generally have favored industrial users. In 1932, in Ohio, the average yield on gas for domestic consumption was 62.1 cents per m.c.f. and on industrial,***636** 38.7. In Pennsylvania, the figures were 62.9 against 31.7. West Virginia showed the least spread, domestic consumers paying 36.6 cents; and industrial, 27.7. FN26 Although this spread is less than ****304** in other parts of the United States, FN27 it can hardly be said to be self-justifying. It certainly is a very great factor in hastening decline of the natural gas supply.

FN26 Brief of National Gas Association and United Mine Workers, supra, note 26, pp. 35, 36, compiled from Bureau of Mines Reports.

FN27 From the source quoted in the preceding note the spread elsewhere is shown to be:

State.	Industrial	Domestic
Illinois.	29.2	1.678
Louisiana.	10.4	59.7
Oklahoma.	11.2	41.5
Texas.	13.1	59.7
Alabama.	17.8	1.227
Georgia.	22.9	1.043

About the time of World War I there were occasional and short-lived efforts by some hard-pressed companies to reverse this discrimination and adopt graduated rates, giving a low rate to quantities adequate for domestic use and graduating it upward to discourage industrial use. FN28 ***637** These rates met opposition from industrial sources, of course, and since diminished revenues from industrial sources tended to increase the domestic price, they met little popular or commission favor. The fact is that neither the gas companies nor the consumers nor local regulatory bodies can be depended upon to conserve gas. Unless federal regulation will take account of conservation, its efforts seem, as in this case, actually to constitute a new threat to the life of the Appalachian supply.

FN28 In Corning, New York, rates were initiated by the Crystal City Gas Company as follows: 70¢ for the first 5,000 cu. ft. per month; 80¢ from 5,000 to 12,000; $1 for all over 12,000. The Public Service Commission rejected these rates and fixed a flat rate of 58¢ per m.c.f. Lane v. Crystal City Gas Co., 8 New York Public Service Comm. Reports, Second District, 210.
The Pennsylvania Gas Company (National Fuel Gas Company group) also attempted a sliding scale rate for New York consumers, net per month as follows: First 5,000 feet, 35¢ ; second 5,000 feet, 45¢ ; third 5,000 feet, 50¢ ; all above 15,000, 55¢ . This was eventually abandoned, however. The company's present scale in Pennsylvania appears to be reversed to the following net monthly rate; first 3 m.c.f., 75¢ ; next 4 m.c.f., 60¢ ; next 8 m.c.f., 55¢ ; over 15 m.c.f., 50¢ . Moody's Manual of Public Utilities (1943) 1350. In New York it now serves a mixed gas.
For a study of effect of sliding scale rates in reducing consumption see 11 Proceedings of Natural Gas Association of America (1919) 287.

II.

Congress in 1938 decided upon federal regulation of the industry. It did so after an exhaustive investigation of all aspects including failing supply and competition for the use of natural gas intensified by growing scarcity. FN29 Pipelines from the Appalachian area to markets were in the control of a handful of holding company systems. FN30 This created a highly concentrated control of the producers' market and of the consumers' supplies. While holding companies dominated both production and distribution they segregated those activities in separate ***638** subsidiaries, FN31 the effect of which, if not the purpose, was to isolate ****305** some end of the business from the reach of any one state commission. The cost of natural gas to consumers moved steadily upwards over the years, out of proportion to prices of oil, which, except for the element of competition, is produced under somewhat comparable conditions. The public came to feel that the companies were exploiting the growing scarcity of local gas. The problems of this region had much to do with creating the demand for federal regulation.

FN29 See Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess.

FN30 Four holding company systems control over 55 per cent of all natural gas transmission lines in the United States. They are Columbia Gas and Electric Corporation, Cities Service Co., Electric Bond and Share Co., and Standard Oil Co. of New Jersey. Columbia alone controls nearly 25 per cent, and fifteen companies account for over 80 per cent of the total. Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 28.

In 1915, so it was reported to the Governor of West

Virginia, 87 per cent of the total gas production of that state was under control of eight companies. Steptoe and Hoffheimer, Legislative Regulation of Natural Gas Supply in West Virginia, 17 West Virginia Law Quarterly 257, 260. Of these, three were subsidiaries of the Columbia system and others were subsidiaries of larger systems. In view of inter-system sales and interlocking interests it may be doubted whether there is much real competition among these companies.

FN31 This pattern with its effects on local regulatory efforts will be observed in our decisions. See United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Co. v. Public Service Commission, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402; Dayton Power & Light v. Public Utilities Commission, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403, and the present case.

The Natural Gas Act declared the natural gas business to be ‘affected with a public interest,’ and its regulation ‘necessary in the public interest.’ [FN32] Originally, and at the time this proceeding was commenced and tried, it also declared ‘the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.’ [FN33] While this was later dropped, there is nothing to indicate that it was not and is not still an accurate statement of purpose of the Act. Extension or improvement of facilities may be ordered when ‘necessary or desirable in the public interest,’ abandonment of facilities may be ordered when the supply is ‘depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity ***639** permit’ abandonment and certain extensions can only be made on finding of ‘the present or future public convenience and necessity.' [FN34] The Commission is required to take account of the ultimate use of the gas. Thus it is given power to suspend new schedules as to rates, charges, and classification of services except where the schedules are for the sale of gas ‘for resale for industrial use only,' [FN35] which gives the companies greater freedom to increase rates on industrial gas than on domestic gas. More particularly, the Act expressly forbids any undue preference or advantage to any person or ‘any unreasonable difference in rates * * * either as between localities or as between classes of service.' [FN36] And the power of the Commission expressly includes that to determine the ‘just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force.' [FN37]

FN32 15 U.S.C. s 717(a), 15 U.S.C.A. s 717(a). (Italics supplied throughout this paragraph.)

FN33 s 7(c), 52 Stat. 825, 15 U.S.C.A. s 717f(c).

FN34 15 U.S.C. s 717f, 15 U.S.C.A. s 717f.

FN35 Id., s 717c(e).

FN36 Id., s 717c(b).

FN37 Id., s 717d(a).

In view of the Court's opinion that the Commission in administering the Act may ignore discrimination, it is interesting that in reporting this Bill both the Senate and the House Committees on Interstate Commerce pointed out that in 1934, on a nationwide average the price of natural gas per m.c.f. was 74.6 cents for domestic use, 49.6 cents for commercial use, and 16.9 for industrial use. [FN38] I am not ready to think that supporters of a bill called attention to the striking fact that householders were being charged five times as much for their gas as industrial users only as a situation which the Bill would do nothing to remedy. On the other hand the Act gave to the Commission what the Court aptly describes as ‘broad powers of regulation.'

FN38 Sen. Rep. No. 1162, 75th Cong., 1st Sess. 2.

***640** III.

This proceeding was initiated by the Cities of Cleveland and Akron. They alleged that the price charged by Hope for natural gas ‘for resale to domestic, commercial and small industrial consumers in Cleveland and elsewhere is excessive, unjust, unreasonable, greatly in excess of the price charged by Hope to nonaffiliated companies at wholesale for resale to domestic, commercial and small industrial consumers, and greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio, and therefore is further unduly discriminatory between consumers and between classes of service’ (italics supplied). The company answered admitting differences in prices to affiliated and nonaffiliated companies and justifying them by differences in conditions of delivery.****306** As to the allegation that the contract price is ‘greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio,' Hope did not deny a price differential, but alleged that industrial gas was not sold to 'favored consumers' but was sold under contract and schedules filed with and approved by the Public Utilities Commission of Ohio, and that certain conditions of delivery made it not 'unduly discriminatory.'

The record shows that in 1940 Hope delivered for industrial consumption 36,523,792 m.c.f. and for domestic and commercial consumption, 50,343,652 m.c.f. I find no separate figure for domestic consumption. It served 43,767 domestic consumers directly, 511,521 through the East Ohio Gas Company, and 154,043 through the Peoples Natural Gas Company, both affiliates owned by the same parent. Its special contracts for industrial consumption, so far as appear, are confined to about a dozen big industries.

***641** Hope is responsible for discrimination as exists in favor of these few industrial consumers. It controls both the resale price and use of industrial gas by virtue of the very interstate sales contracts over which the Commission is exercising its jurisdiction.

Hope's contract with East Ohio Company is an example. Hope agrees to deliver, and the Ohio Company to take, '(a) all natural gas requisite for the supply of the domestic consumers of the Ohio Company; (b) such amounts of natural gas as may be requisite to fulfill contracts made with the consent and approval of the Hope Company by the Ohio Company, or companies which it supplies with natural gas, for the sale of gas upon special terms and conditions for manufacturing purposes.' The Ohio company is required to read domestic customers' meters once a month and meters of industrial customers daily and to furnish all meter readings to Hope. The Hope Company is to have access to meters of all consumers and to all of the Ohio Company's accounts. The domestic consumers of the Ohio Company are to be fully supplied in preference to consumers purchasing for manufacturing purposes and 'Hope Company can be required to supply gas to be used for manufacturing purposes only where the same is sold under special contracts which have first been submitted to and approved in writing by the Hope Company and which expressly provide that natural gas will be supplied thereunder only in so far as the same is not necessary to meet the requirements of domestic consumers supplied through pipe lines of the Ohio Company.' This basic contract was supplemented from time to time, chiefly as to price. The last amendment was in a letter from Hope to East Ohio in 1937. It contained a special discount on industrial gas and a schedule of special industrial contracts, Hope reserving the right to make eliminations therefrom and agreeing that others might be added from time to ***642** time with its approval in writing. It said, 'It is believed that the price concessions contained in this letter, while not based on our costs, are under certain conditions, to our mutual advantage in maintaining and building up the volumes of gas sold by us (italics supplied).' FN39

FN39 The list of East Ohio Gas Company's special industrial contracts thus expressly under Hope's control and their demands are as follows:

****307** The Commission took no note of the charges of discrimination and made no disposition of the issue tendered on this point. It ordered a flat reduction in the price per m.c.f. of all gas delivered by Hope in interstate commerce. It made no limitation, condition, or provision as to what classes of consumers should get the benefit of the reduction. While the cities have accepted and are defending the reduction, it is my view that the discrimination of which they have complained is perpetuated and increased by the order of the Commission and that it violates the Act in so doing.

The Commission's opinion aptly characterizes its entire objective by saying that 'bona fide investment figures now become all-important in the regulation of rates.' It should be noted that the all-importance of this theory is not the result of any instruction from Congress. When the Bill to regulate gas was first before Congress it contained***643** the following: 'In determining just and reasonable rates the Commission shall fix such rate as will allow a fair return upon the actual legitimate prudent cost of the property used and useful for the service in question.' H.R. 5423, 74th Cong., 1st Sess. Title III, s 312(c). Congress rejected this language. See H.R. 5423, s 213 (211(c)), and H.R. Rep. No. 1318, 74th Cong., 1st Sess. 30.

The Commission contends nevertheless that the 'all important' formula for finding a rate base is that of prudent investment. But it excluded from the investment base an amount actually and admittedly invested of some $17,000,000. It did so because it says that the Company recouped these expenditures from customers before the days of regulation from earnings above a fair return. But it would not apply all of such 'excess earnings' to reduce the rate base as one of the Commissioners suggested. The reason for applying excess earnings to reduce the investment base roughly from $69,000,000 to $52,000,000 but refusing to apply them to reduce it from that to some $18,000,000 is not found in a difference in the character of the earnings or in their reinvestment. The reason assigned is a difference in bookkeeping treatment many years before the Company was subject to regulation. The $17,000,000, reinvested chiefly in well drilling, was treated on the books as expense. (The Commission now requires that drilling costs be carried to capital account.) The allowed rate base thus actually was determined by the Company's bookkeeping, not its investment. This attributes a significance to formal classification in account keeping that seems inconsistent with rational rate regulation. FN40 Of ***644** course, the ****308** Commission would not and should not allow a rate base to be inflated by bookkeeping which had improperly capitalized expenses. I have doubts about resting public regulation upon any rule that is to be used or not depending on which side it favors.

FN40 To make a fetish of mere accounting is to shield from examination the deeper causes, forces, movements, and conditions which should govern rates. Even as a recording of current transactions, bookkeeping is hardly an exact science. As a representation of the condition and trend of a business, it uses symbols of certainty to express values that actually are in constant flux. It may be said that in commercial or investment banking or any business extending credit success depends on knowing what not to believe in accounting. Few concerns go into bankruptcy or reorganization whose books do not show them solvent and often even profitable. If one cannot rely on accountancy accurately to disclose past or current conditions of a business, the fallacy of using it as a sole guide to future price policy ought to be apparent. However, our quest for certitude is so ardent that we pay an irrational reverence to a technique which uses symbols of certainty, even though experience again and again warns us that they are delusive. Few writers have ventured to challenge this American idolatry, but see Hamilton, Cost as a standard for Price, 4 Law and Contemporary Problems 321, 323-25. He observes that ‘As the apostle would put it, accountancy is all things to all men. * * * Its purpose determines the character of a system of accounts.’ He analyzes the hypothetical character of accounting and says ‘It was no eternal mold for pecuniary verities handed down from on high. It was-like logic or algebra, or the device of analogy in the law-an ingenious contrivance of the human mind to serve a limited and practical purpose.’ ‘Accountancy is far from being a pecuniary expression of all that is industrial reality. It is an instrument, highly selective in its application, in the service of the institution of money making.’ As to capital account he observes ‘In an enterprise in lusty competition with others of its kind, survival is the thing and the system of accounts has its focus in solvency. * * * Accordingly depreciation, obsolescence, and other factors which carry no immediate threat are matters of lesser concern and the capital account is likely to be regarded as a secondary phenomenon. * * * But in an enterprise, such as a public utility, where continued survival seems assured, solvency is likely to be taken for granted. * * * A persistent and ingenious attention is likely to be directed not so much to securing the upkeep of the physical property as to making it certain that capitalization fails in not one whit to give full recognition to every item that should go into the account.'

***645** The Company on the other hand, has not put its gas fields into its calculations on the present-value basis, although that, it contends, is the only lawful rule for finding a rate base. To do so would result in a rate higher than it has charged or proposes as a matter of good business to charge.

The case before us demonstrates the lack of rational relationship between conventional rate-base formulas and natural gas production and the extremities to which regulating bodies are brought by the effort to rationalize them. The Commission and the Company each stands on a different theory, and neither ventures to carry its theory to logical conclusion as applied to gas fields.

IV.

This order is under judicial review not because we interpose constitutional theories between a State and the business it seeks to regulate, but because Congress put upon the federal courts a duty toward administration of a new federal regulatory Act. If we are to hold that a given rate is reasonable just because the Commission has said it was reasonable, review becomes a costly, time-consuming pageant of no practical value to anyone. If on the other hand we are to bring judgment of our own to the task, we should for the guidance of the regulators and the regulated reveal something of the philosophy, be it legal or economic or social, which guides us. We need not be slaves to a formula but unless we can point out a rational way of reaching our conclusions they can only be accepted as resting on intuition or predilection. I must admit that I possess no instinct jby which to know the ‘reasonable’ from the ‘unreasonable’ in prices and must seek some conscious design for decision.

The Court sustains this order as reasonable, but what makes it so or what could possibly make it otherwise,

***646** I cannot learn. It holds that: 'it is the result reached not the method employed which is controlling'; 'the fact that the method employed to reach that result may contain infirmities is not then important' and it is not 'important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at.' The Court does lean somewhat on considerations of capitalization and dividend history and requirements for dividends on outstanding stock. But I can give no real weight to that for it is generally and I think deservedly in discredit as any guide in rate cases. FN41

FN41 See 2 Bonbright, Valuation of Property (1937) 1112.

Our books already contain so much talk of methods of rationalizing rates that we must appear ambiguous if we announce results without our working methods. We are confronted with regulation of a unique type of enterprise which I think requires considered rejection of much conventional utility doctrine and adoption of concepts of 'just and reasonable' rates and practices and of the 'public interest' that will take account of the peculiarities of the business.

The Court rejects the suggestions of this opinion. It says that the Committees in reporting the bill which became the Act said it provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions.' So saying it sustains a rate calculated on a novel variation of a rate base theory which itself had at the time of enactment of the legislation been recognized only in dissenting opinions. Our difference seems to be between unconscious innovation, FN42 and the purposeful ****309** and deliberate innovation I ***647** would make to meet the necessities of regulating the industry before us.

FN42 Bonbright says, '* * * the vice of traditional law lies, not in its adoption of excessively rigid concepts of value and rules of valuation, but rather in its tendency to permit shifts in meaning that are inept, or else that are ill-defined because the judges that make them will not openly admit that they are doing so.' Id., 1170.

Hope's business has two components of quite divergent character. One, while not a conventional common-carrier undertaking, is essentially a transportation enterprise consisting of conveying gas from where it is produced to point of delivery to the buyer. This is a relatively routine operation not differing substantially from many other utility operations. The service is produced by an investment in compression and transmission facilities. Its risks are those of investing in a tested means of conveying a discovered supply of gas to a known market. A rate base calculated on the prudent investment formula would seem a reasonably satisfactory measure for fixing a return from that branch of the business whose service is roughly proportionate to the capital invested. But it has other consequences which must not be overlooked. It gives marketability and hence 'value' to gas owned by the company and gives the pipeline company a large power over the marketability and hence 'value' of the production of others.

The other part of the business-to reduce to possession an adequate supply of natural gas-is of opposite character, being more erratic and irregular and unpredictable in relation to investment than any phase of any other utility business. A thousand feet of gas captured and severed from real estate for delivery to consumers is recognized under our law as property of much the same nature as a ton of coal, a barrel of oil, or a yard of sand. The value to be allowed for it is the real battleground between the investor and consumer. It is from this part of the business that the chief difference between the parties as to a proper rate base arises.

It is necessary to a 'reasonable' price for gas that it be anchored to a rate base of any kind? Why did courts in the first place begin valuing 'rate bases' in order to 'value' something else? The method came into vogue ***648** in fixing rates for transportation service which the public obtained from common carriers. The public received none of the carriers' physical property but did make some use of it. The carriage was often a monopoly so there were no open market criteria as to reasonableness. The 'value' or 'cost' of what was put to use in the service by the carrier was not a remote or irrelevant consideration in making such rates. Moreover the difficulty of appraising an intangible service was thought to be simplified if it could be related to physical property which was visible and measurable and the items of which might have market value. The court hoped to reason from the known to the unknown. But gas fields turn this method topsy turvy. Gas itself is tangible, possessible, and does have a market and a price in the field. The value of the rate base is more elusive than that of gas. It consists of intangibles-leaseholds and freeholds-operated and unoperated-of little use in themselves except as rights to reach and capture gas. Their value lies almost wholly in predictions of discovery, and of price of gas when captured, and bears little relation to cost of tools and supplies and labor to develop it. Gas is what Hope sells and it can be directly priced more reasonably and easily and accurately than the components of a rate base can be valued. Hence the reason for resort to a roundabout way of rate base price fixing does not exist in the case of gas in the field.

But if found, and by whatever method found, a rate base is little help in determining reasonableness of the price of gas. Appraisal of present value of these intangible rights to pursue fugitive gas depends on the value assigned to the gas when captured. The 'present fair value' rate base, generally in ill repute, FN43 is not even ****310** urged by the gas company for valuing its fields.

FN43 'The attempt to regulate rates by reference to a periodic or occasional reappraisal of the properties has now been tested long enough to confirm the worst fears of its critics. Unless its place is taken by some more promising scheme of rate control, the days of private ownership under government regulation may be numbered.' 2 Bonbright, Valuation of Property (1937) 1190.

***649** The prudent investment theory has relative merits in fixing rates for a utility which creates its service merely by its investment. The amount and quality of service rendered by the usual utility will, at least roughly, be measured by the amount of capital it puts into the enterprise. But it has no rational application where there is no such relationship between investment and capacity to serve. There is no such relationship between investment and amount of gas produced. Let us assume that Doe and Roe each produces in West Virginia for delivery to Cleveland the same quantity of natural gas per day. Doe, however, through luck or foresight or whatever it takes, gets his gas from investing $50,000 in leases and drilling. Roe drilled poorer territory, got smaller wells, and has invested $250,000. Does anybody imagine that Roe can get or ought to get for his gas five times as much as Doe because he has spent five times as much? The service one renders to society in the gas business is measured by what he gets out of the ground, not by what he puts into it, and there is little more relation between the investment and the results than in a game of poker.

Two-thirds of the gas Hope handles it buys from about 340 independent producers. It is obvious that the principle of rate-making applied to Hope's own gas cannot be applied, and has not been applied, to the bulk of the gas Hope delivers. It is not probable that the investment of any two of these producers will bear the same ratio to their investments. The gas, however, all goes to the same use, has the same utilization value and the same ultimate price.

To regulate such an enterprise by undiscriminatingly transplanting any body of rate doctrine conceived and ***650** adapted to the ordinary utility business can serve the 'public interest' as the Natural Gas Act requires, if at all, only by accident. Mr. Justice Brandeis, the pioneer juristic advocate of the prudent investment theory for man-made utilities, never, so far as I am able to discover, proposed its application to a natural gas case. On the other hand, dissenting in Commonwealth of Pennsylvania v. West Virginia, he reviewed the problems of gas supply and said, 'In no other field of public service regulation is the controlling body confronted with factors so baffling as in the natural gas industry, and in none is continuous supervision and control required in so high a degree.' 262 U.S. 553, 621, 43 S.Ct. 658, 674, 67 L.Ed. 1117, 32 A.L.R. 300. If natural gas rates are intelligently to be regulated we must fit our legal principles to the economy of the industry and not try to fit the industry to our books.

As our decisions stand the Commission was justified in believing that it was required to proceed by the rate base method even as to gas in the field. For this reason the Court may not merely wash its hands of the method and rationale of rate making. The fact is that this Court, with no discussion of its fitness, simply transferred the rate base method to the natural gas industry. It happened in Newark Natural Gas & Fuel Co. v. City of Newark, Ohio, 1917, 242 U.S. 405, 37 S.Ct. 156, 157, 61 L.Ed. 393, Ann.Cas.1917B, 1025, in which the company wanted 25 cents per m.c.f., and under the Fourteenth Amendment challenged the reduction to 18 cents by ordinance. This Court sustained the reduction because the court below 'gave careful consideration to the questions of the value of the property * * * at the time of the inquiry,' and whether the rate 'would be sufficient to provide a fair return on the value of the property.' The Court said this method was 'based upon principles thoroughly established by repeated secisions of this court,' citing many cases, not one of which involved natural gas or a comparable wasting natural resource. Then came issues as to state power to ***651** regulate as affected by the commerce clause. Public Utilities Commission v. Landon, 1919, 249 U.S. 236, 39 S.Ct. 268, 63 L.Ed. 577; Pennsylvania Gas Co. v. Public Service Commission, 1920, 252 U.S. 23, 40 S.Ct. 279, 64 L.Ed. 434. These questions settled, the Court again was called upon in natural gas cases to consider state rate-making claimed to be invalid under the Fourteenth Amendment. United Fuel Gas Co. v. Railroad Commission of Kentucky, 1929, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Company v. Public Service Commission of West Virginia, 1929, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402. Then, as now, the differences were 'due ****311** chiefly to the difference in value ascribed by each to the gas rights and leaseholds.' 278 U.S. 300, 311, 49 S.Ct. 150, 153, 73 L.Ed. 390. No one seems to have questioned that the rate base method must be pursued and the controversy was at what rate base must be used. Later the 'value' of gas in the field was questioned in determining the amount a regulated company should be allowed to pay an affiliate therefor-a state determination also reviewed under the Fourteenth Amendment. Dayton Power & Light Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403. In both cases, one of which sustained, and one of which struck down a fixed rate the Court assumed the rate base method, as the legal way of testing reasonableness of natural gas prices fixed by public authority, without examining its real relevancy to the inquiry.

Under the weight of such precedents we cannot expect the Commission to initiate economically intelligent methods of fixing gas prices. But the Court now faces a new plan of federal regulation based on the power to fix the price at which gas shall be allowed to move in interstate commerce. I should now consider whether these rules devised under the Fourteenth Amendment are the exclusive tests of a just and reasonable rate under the federal statute, inviting reargument directed to that point ***652** if necessary. As I see it now I would be prepared to hold that these rules do not apply to a natural gas case arising under the Natural Gas Act.

Such a holding would leave the Commission to fix the price of gas in the field as one would fix maximum prices of oil or milk or coal, or any other commodity. Such a price is not calculated to produce a fair return on the synthetic value of a rate base of any individual producer, and would not undertake to assure a fair return to any producer. The emphasis would shift from the producer to the product, which would be regulated with an eye to average or typical producing conditions in the field.

Such a price fixing process on economic lines would offer little temptation to the judiciary to become back seat drivers of the price fixing machine. The unfortunate effect of judicial intervention in this field is to divert the attention of those engaged in the process from what is economically wise to what is legally permissible. It is probable that price reductions would reach economically unwise and self-defeating limits before they would reach constitutional ones. Any constitutional problems growing out of price fixing are quite different than those that have heretofore been considered to inhere in rate making. A producer would have difficulty showing the invalidity of such a fixed price so long as he voluntarily continued to sell his product in interstate commerce. Should he withdraw and other authority be invoked to compel him to part with his property, a different problem would be presented.

Allowance in a rate to compensate for gas removed from gas lands, whether fixed as of point of production or as of point of delivery, probably best can be measured by a functional test applied to the whole industry. For good or ill we depend upon private enterprise to exploit these natural resources for public consumption. The function which an allowance for gas in the field should perform ***653** for society in such circumstances is to be enough and no more than enough to induce private enterprise completely and efficiently to utilize gas resources, to acquire for public service any available gas or gas rights and to deliver gas at a rate and for uses which will be in the future as well as in the present public interest.

The Court fears that 'if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine * * *.' With due deference I suggest that there is nothing novel in the idea that any change in price of a service or commodity reacts to encourage or discourage its use. The question is not whether such consequences will or will not follow; the question is whether effects must be suffered blindly or may be intelligently selected, whether price control shall have targets at which it deliberately aims or shall be handled like a gun in the hands of one who does not know it is loaded.

We should recognize 'price' for what it is-a tool, a means, an expedient. In public****312** hands it has much the same economic effects as in private hands. Hope knew that a concession in industrial price would tend to build up its volume of sales. It used price as an expedient to that end. The Commission makes another cut in that same price but the Court thinks we should ignore the effect that it will have on exhaustion of supply. The fact is that in natural gas regulation price must be used to reconcile the private property right society has permitted to vest in an important natural resource with the claims of society upon it-price must draw a balance between wealth and welfare.

To carry this into techniques of inquiry is the task of the Commissioner rather than of the judge, and it certainly is no task to be solved by mere bookkeeping but requires the best economic talent available. There would doubtless be inquiry into the price gas is bringing in the ***654** field, how far that price is established by arms' length bargaining and how far it may be influenced by agreements in restraint of trade or monopolistic influences. What must Hope really pay to get and to replace gas it delivers under this order? If it should get more or less than that for its own, how much and why? How far are such prices influenced by pipe line access to markets and if the consumers pay returns on the pipe lines how far should the increment they cause go to gas producers? East Ohio is itself a producer in Ohio. FN44 What do Ohio authorities require Ohio consumers to pay for gas in the field? Perhaps these are reasons why the Federal Government should put West Virginia gas at lower or at higher rates. If so what are they? Should East Ohio be required to exploit its half million acres of unoperated reserve in Ohio before West Virginia resources shall be supplied on a devalued basis of which that State complains and for which she threatens measures of self keep? What is gas worth in terms of other fuels it displaces?

FN44 East Ohio itself owns natural gas rights in 550,600 acres, 518,526 of which are reserved and 32,074 operated, by 375 wells. Moody's Manual of Public Utilities (1943) 5.

A price cannot be fixed without considering its effect on the production of gas. Is it an incentive to continue to exploit vast unoperated reserves? Is it conducive to deep drilling tests the result of which we may know only after trial? Will it induce bringing gas from afar to supplement or even to substitute for Appalachian gas? FN45 Can it be had from distant fields as cheap or cheaper? If so, that competitive potentiality is certainly a relevant consideration. Wise regulation must also consider, as a private buyer would, what alternatives the producer has ***655** if the price is not acceptable. Hope has intrastate business and domestic and industrial customers. What can it do by way of diverting its supply to intrastate sales? What can it do by way of disposing of its operated or reserve acreage to industrial concerns or other buyers? What can West Virginia do by way of conservation laws, severance or other taxation, if the regulated rate offends? It must be borne in mind that while West Virginia was prohibited from giving her own inhabitants a priority that discriminated against interstate commerce, we have never yet held that a good faith conservation act, applicable to her own, as well as to others, is not valid. In considering alternatives, it must be noted that federal regulation is very incomplete, expressly excluding regulation of 'production or gathering of natural gas,' and that the only present way to get the gas seems to be to call it forth by price inducements. It is plain that there is a downward economic limit on a safe and wise price.

FN45 Hope has asked a certificate of convenience and necessity to lay 1140 miles of 22-inch pipeline from Hugoton gas fields in southwest Kansas to West Virginia to carry 285 million cu. ft. of natural gas per day. The cost was estimated at $51,000,000. Moody's Manual of Public Utilities (1943) 1760.

But there is nothing in the law which compels a commission to fix a price at that 'value' which a company might give to its product by taking advantage of scarcity, or monopoly of supply. The very purpose of fixing maximum prices is to take away from the seller his opportunity to get all that otherwise the market would award him for his goods. This is a constitutional use of the power to fix maximum prices, ****313**Block v. Hirsh, 256 U.S. 135, 41 S.Ct. 458, 65 L.Ed. 865, 16 A.L.R. 165; Marcus Brown Holding Co. v. Feldman, 256 U.S. 170, 41 S.Ct. 465, 65 L.Ed. 877; International Harvester Co. v. Kentucky, 234 U.S. 216, 34 S.Ct. 853, 58 L.Ed. 1284; Highland v. Russell Car & Snow Plow Co., 279 U.S. 253, 49 S.Ct. 314, 73 L.Ed. 688, just as the fixing of minimum prices of goods in interstate commerce is constitutional although it takes away from the buyer the advantage in bargaining which market conditions would give him. United States v. Darby, 312 U.S. 100, 657, 61 S.Ct. 451, 85 L.Ed. 609, 132 A.L.R. 1430; Mulford v. Smith, 307 U.S. 38, 59 S.Ct. 648, 83 L.Ed. 1092; United States v. Rock Royal Co-operative, Inc., 307 U.S. 533, 59 S.Ct. 993, 83 L.Ed. 1446; Sunshine Anthracite Coal Co. v. Adkins, 310 U.S. 381, 60 S.Ct. 907, 84 L.Ed. 1263. The Commission has power to fix ***656** a price that will be both maximum and minimum and it has the incidental right, and I think the duty, to choose the economic consequences it will promote or retard in production and also more importantly in consumption, to which I now turn.

If we assume that the reduction in company revenues is warranted we then come to the question of translating the allowed return into rates for consumers or classes of consumers. Here the Commission fixed a single rate for all gas delivered irrespective of its use despite the fact that Hope has established what amounts to two rates-a high one for domestic use and a lower one for industrial contracts. FN46 The Commission can fix two prices for interstate gas as readily as one-a price for resale to domestic users and another for resale to industrial users. This is the pattern Hope itself has established in the very contracts over which the Commission is expressly given jurisdiction. Certainly the Act is broad enough to permit two prices to be fixed instead of one, if the concept of the 'public interest' is not unduly narrowed.

FN46 I find little information as to the rates for industries in the record and none at all in such usual sources as Moody's Manual.

The Commission's concept of the public interest in natural gas cases which is carried today into the Court's opinion was first announced in the opinion of the minority in the Pipeline case. It enumerated only two 'phases of the public interest: (1) the investor interest; (2) the consumer interest,' which it emphasized to the exclusion of all others. 315 U.S. 575, 606, 62 S.Ct. 736, 753, 86 L.Ed. 1037. This will do well enough in dealing with railroads or utilities supplying manufactured gas, electric, power, a communications service or transportation, where utilization of facilities does not impair their future usefulness. Limitation of supply, however, brings into a natural gas case another phase of the public interest that to my mind overrides both the owner ***657** and the consumer of that interest. Both producers and industrial consumers have served their immediate private interests at the expense of the long-range public interest. The public interest, of course, requires stopping unjust enrichment of the owner. But it also requires stopping unjust impoverishment of future generations. The public interest in the use by Hope's half million domestic consumers is quite a different one from the public interest in use by a baker's dozen of industries.

Prudent price fixing it seems to me must at the very threshold determine whether any part of an allowed return shall be permitted to be realized from sales of gas for resale for industrial use. Such use does tend to level out daily and seasonal peaks of domestic demand and to some extent permits a lower charge for domestic service. But is that a wise way of making gas cheaper when, in comparison with any substitute, gas is already a cheap fuel? The interstate sales contracts provide that at times when demand is so great that there is not enough gas to go around domestic users shall first be served. Should the operation of this preference await the day of actual shortage? Since the propriety of a preference seems conceded, should it not operate to prevent the coming of a shortage as well as to mitigate its effects? Should industrial use jeopardize tomorrow's service to householders any more than today's? If, however, it is decided to cheapen domestic use by resort to industrial sales, should they be limited to the few uses ****314** for which gas has special values or extend also to those who use it only because it is cheaper than competitive fuels? FN47 And how much cheaper should industrial***658** gas sell than domestic gas, and how much advantage should it have over competitive fuels? If industrial gas is to contribute at all to lowering domestic rates, should it not be made to contribute the very maximum of which it is capable, that is, should not its price be the highest at which the desired volume of sales can be realized?

> FN47 The Federal Power Commission has touched upon the problem of conservation in connection with an application for a certificate permitting construction of a 1500-mile pipeline from southern Texas to New York City and says: 'The Natural Gas Act as presently drafted does not enable the Commission to treat fully the serious implications of such a problem. The question should be raised as to whether the proposed use of natural gas would not result in displacing a less valuable fuel and create hardships in the industry already supplying the market, while at the same time rapidly depleting the country's natural-gas reserves. Although, for a period of perhaps 20 years, the natural gas could be so priced as to appear to offer an apparent saving in fuel costs, this would mean simply that social costs which must eventually be paid had been ignored.

'Careful study of the entire problem may lead to the conclusion that use of natural gas should be restricted by functions rather than by areas. Thus, it is especially adapted to space and water heating in urban homes and other buildings and to the various industrial heat processes which require concentration of heat, flexibility of control, and uniformity of results. Industrial uses to which it appears particularly adapted include the treating and annealing of metals, the operation of kilns in the ceramic, cement, and lime industries, the manufacture of glass in its various forms, and use as a raw material in the chemical industry. General use of natural gas under boilers for the production of steam is, however, under most circumstances of very questionable social economy.' Twentieth Annual Report of the Federal Power Commission (1940) 79.

If I were to answer I should say that the household rate should be the lowest that can be fixed under commercial conditions that will conserve the supply for that use. The lowest probable rate for that purpose is not likely to speed exhaustion much, for it still will be high enough to induce economy, and use for that purpose has more nearly reached the saturation point. On the other hand the demand for industrial gas at present rates already appears to be increasing. To lower further the industrial rate is merely further to subsidize industrial consumption and speed depletion. The impact of the flat reduction ***659** of rates ordered here admittedly will be to increase the industrial advantages of gas over competing fuels and to increase its use. I think this is not, and there is no finding by the Commission that it is, in the public interest.

There is no justification in this record for the present discrimination against domestic users of gas in favor of industrial users. It is one of the evils against which the Natural Gas Act was aimed by Congress and one of the evils complained of here by Cleveland and Akron. If

Hope's revenues should be cut by some $3,600,000 the whole reduction is owing to domestic users. If it be considered wise to raise part of Hope's revenues by industrial purpose sales, the utmost possible revenue should be raised from the least consumption of gas. If competitive relationships to other fuels will permit, the industrial price should be substantially advanced, not for the benefit of the Company, but the increased revenues from the advance should be applied to reduce domestic rates. For in my opinion the 'public interest' requires that the great volume of gas now being put to uneconomic industrial use should either be saved for its more important future domestic use or the present domestic user should have the full benefit of its exchange value in reducing his present rates.

Of course the Commission's power directly to regulate does not extend to the fixing of rates at which the local company shall sell to consumers. Nor is such power required to accomplish the purpose. As already pointed out, the very contract the Commission is altering classifies the gas according to the purposes for which it is to be resold and provides differentials between the two classifications. It would only be necessary for the Commission to order ****315** that all gas supplied under paragraph (a) of Hope's contract with the East Ohio Company shall be ***660** at a stated price fixed to give to domestic service the entire reduction herein and any further reductions that may prove possible by increasing industrial rates. It might further provide that gas delivered under paragraph (b) of the contract for industrial purposes to those industrial customers Hope has approved in writing shall be at such other figure as might be found consistent with the public interest as herein defined. It is too late in the day to contend that the authority of a regulatory commission does not extend to a consideration of public interests which it may not directly regulate and a conditioning of its orders for their protection. Interstate Commerce Commission v. Railway Labor Executives Ass'n, 315 U.S. 373, 62 S.Ct. 717, 86 L.Ed. 904; United States v. Lowden, 308 U.S. 225, 60 S.Ct. 248, 84 L.Ed. 208.

Whether the Commission will assert its apparently broad statutory authorization over prices and discriminations is, of course, its own affair, not ours. It is entitled to its own notion of the 'public interest' and its judgment of policy must prevail. However, where there is ground for thinking that views of this Court may have constrained the Commission to accept the rate-base method of decision and a particular single formula as 'all important' for a rate base, it is appropriate to make clear the reasons why I, at least, would not be so understood. The Commission is free to face up realistically to the nature and peculiarity of the resources in its control, to foster their duration in fixing price, and to consider future interests in addition to those of investors and present consumers. If we return this case it may accept or decline the proffered freedom. This problem presents the Commission an unprecedented opportunity if it will boldly make sound economic considerations, instead of legal and accounting theories, the foundation of federal policy. I would return the case to the Commission and thereby be clearly quit of what now may appear to be some responsibility for perpetrating a shortsighted pattern of natural gas regulation.

U.S. 1944.
Federal Power Commission v. Hope Natural Gas Co.
51 P.U.R.(NS) 193, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333

END OF DOCUMENT

278.030 Rates, classifications and service of utilities to be just and reasonable -- Service to be adequate -- Utilities prohibited from energizing power to electrical service where seal is not present.

(1) Every utility may demand, collect and receive fair, just and reasonable rates for the services rendered or to be rendered by it to any person.

(2) Every utility shall furnish adequate, efficient and reasonable service, and may establish reasonable rules governing the conduct of its business and the conditions under which it shall be required to render service.

(3) Every utility may employ in the conduct of its business suitable and reasonable classifications of its service, patrons and rates. The classifications may, in any proper case, take into account the nature of the use, the quality used, the quantity used, the time when used, the purpose for which used, and any other reasonable consideration.

(4) Notwithstanding the provisions of subsection (2) of this section, no utility shall energize power to an electrical service in a manufactured home or mobile home where the certified installer's seal is not present pursuant to KRS 227.570.

(5) Notwithstanding the provisions of subsection (2) of this section, no utility shall energize power to an electrical service in a previously owned manufactured home or previously owned mobile home where the Class B1 seal is not present pursuant to KRS 227.600.

Effective: January 1, 2009

History: Amended 2008 Ky. Acts ch. 118, sec. 3, effective January 1, 2009. -- Amended 1976 Ky. Acts ch. 88, sec. 1, effective March 29, 1976. -- Recodified 1942 Ky. Acts ch. 208, sec. 1, effective October 1, 1942, from Ky. Stat. secs. 3952-28, 3952-29.

PSC responds to criticism of Ky. Power

Letters to the Editor
By Mountain Eagle Staff | on January 29, 2014

To the Editor:

The Kentucky Public Service Commission (PSC) welcomes this opportunity to respond to certain statements by members of the Letcher County Fiscal Court, as reported in *The Mountain Eagle's* January 22 edition.

Those statements left the impression that recent high utility bills are the result of unspecified "rate increases" granted to Kentucky Power Company by the PSC. The statement further implied that the so-called rate increases were driven by both conversion of coalfi red power plants to natural gas and increased executive pay and shareholder dividends at parent company American Electric Power (AEP).

Here are the facts:

2. In October 2013, in case 2012-00578, the PSC authorized Kentucky Power to collect a surcharge to begin paying for the purchase of a coal-fired power plant to replace the larger portion of the Big Sandy power plant in Louisa. That modest temporary surcharge took effect this month.

3. At the same time that it authorized the surcharge, the PSC froze Kentucky Power's base rates until May of 2015.

4. All of Kentucky Power's current generating capacity is coalfi red. The company has requested the PSC's permission to convert a portion of the Big Sandy plant to run on natural gas. No decision has been made in that case, which is number 2013-00430.

5. Like every other investorowned utility in the state, Kentucky Power is entitled – by both Kentucky and federal law – to the opportunity to earn a reasonable but not excessive rate of return on equity for its shareholders.

6. It is from that rate of return – what may be viewed as profit – that parent company AEP pays dividends, lobbying expenses, executive bonuses and other items. Those costs are not used to calculate Kentucky Power's base rates.

7. Kentucky Power is the smallest operating company within AEP. That means that its ratepayers pay a relatively small proportion of those parent company costs that are reflected in base rates and contribute a similarly small proportion of the overall parent company profits and returns to shareholders.

8. Kentucky Power's rates, which are determined on a standalone basis, are driven overwhelmingly by two factors: its day-to-day operating expenses and the cost of ownership of its generating facilities, which at present are all fueled by coal. Those factors, and the calculation of a reasonable rate of return on equity, are what the PSC uses when it sets base rates that it determines to be fair, just and reasonable.

9. Base rates change only at several-year intervals. Other items that help determine the total utility bill, such as an adjustment for fluctuations in the price of coal, may rise or fall on a monthly basis, but differ little from one month to the next.

10. By far the single largest factor in determining the amount of an electric bill every month is consumption – how much electricity an individual customer uses.

In one respect, the members of the Letcher County Fiscal Court are correct: electric bills in the last two months or so have been higher than in the preceding months. The reason is obvious. It has been cold, particularly this month.

than normal. December, despite two cold snaps, was actually a bit warmer than average. But January thus far has been especially cold, with average daily temperatures about six degrees below normal and heating demand well above normal as a result. The heating demand does not take into account wind speeds, which can amplify the effect of cold temperatures.

The cold weather means that it takes more energy to heat a home – regardless of whether it is heated with electricity, natural gas, propane, coal or firewood. It will simply take more fuel, and that means it will cost more. Because the cost of electricity – unlike other heating fuels – is regulated by the PSC, the higher Kentucky Power bills have little to do with rates and everything to do with the weather.

Much as we might like to, none of us can do anything about the weather. However, there are things everyone can do to manage their energy costs.

First and foremost is to improve the energy efficiency of your home. There are many simple steps that help keep cold air out and warm air in. Information is available from a variety of sources, including Community Action Agencies and utility companies.

Many community agencies and utility companies, including Kentucky Power, have programs to assist residents in weatherizing their homes. In fact, the PSC in October ordered Kentucky Power to increase funding for its weatherization and other energy efficiency programs.

Weatherization can help with future bills. There is also help available for those who have difficulty paying their current electric bills. The PSC recognizes that the economic situation has in recent years placed many people into that position for the first time.

That is why the PSC ordered Kentucky Power to increase the contribution AEP's shareholders make to a program to assist lowincome customers who are having difficulty paying their electric bills. Information on the program is available from Kentucky Power. Other sources of assistance also are available, notably the Low Income Heating Assistance Program, or LIHEAP, which is administered by the Leslie-Knott- Letcher-Perry Community Action Agency.

It is also important to know that utility companies are required to offer budget billing plans, which average bills over a 12-month period and thus reduce seasonal fluctuations in monthly bills. Utilities also are required to offer customers faced with disconnection for non-payment the opportunity to enter into installment payment plans.

toll-free number is 800-772-4636.

Finally, it bears noting that this is not the first time that this issue has arisen in Letcher County. The early winter of 2010-2011 was even colder than this winter has been thus far, particularly in December.

In February of 2011, at the request of the Letcher County Fiscal Court, PSC staff and others conducted a home energy workshop at the Letcher County Courthouse in Whitesburg. Many Letcher County residents attended, including a number of local elected officials. That workshop covered in greater depth much of the information presented in this letter, including a detailed explanation – using actual Kentucky Power Company bills – of the relationship between weather, energy usage and utility bills.

Many of the Letcher Countians who attended that workshop said that the information was useful and gave them a better understanding of their electric bills, even if it did not reduce their concerns about the size of those bills.

Unhappiness with large utility bills is only natural. The PSC accepts that it will be the focus of some of that displeasure, despite its efforts to keep rates as low as possible and its inability to control the weather.

The PSC will continue to provide utility customers in Letcher County and across Kentucky with accurate and timely information that helps them understand and manage their utility bills.

The PSC thanks *The Mountain Eagle* for this opportunity to set the record straight.

ANDREW MELNYKOVYCH

Communications Director/

Public Information Officer

Public Service Commission

Frankfort, Ky.

More From Opinions

Go To The Opinions Section

The (political) age problem

Dilemma for moderate GOPers

Leave a Reply

Your email address will not be published. Required fields are marked *

Comment

Name *

Website

Post Comment

INDUSTRY TIMELINESS: 71 (of 97)

Historically, the Water Utility Industry has attracted conservative, income-oriented investors. This has been changing of late, however.

The Federal Reserve continued to pursue a more-restrictive monetary policy last month. Treasury notes and bill compete with income stocks for investors' funds. Should the Fed hike short-term rates further, the more attractive they will become on a comparison basis to this group.

Almost every utility has a large capital budget as the companies are trying to modernize the nation's aging pipelines and wastewater facilities.

Consolidation continues in this industry as the market is incredibly splintered.

In the recent past, regulators have generally been constructive when dealing with water utilities. The regulatory climate of a state has a major impact on how a utility performs.

Even though the Water Utility Industry's ranking has moved higher over the past three months, it still is in the third quartile.

Fish or Fowl?

Traditionally, investors have flocked to water utilities for the current income, dividend growth potential, low Beta-coefficients, and well-defined business prospects. These equities tended to trail the market averages during rallies and outperform in downturns. About three years ago, this correlation began to deteriorate. Total returns of this group started to do well in a bull market. It's only been over the past 12 months or so that the previous relationship has returned.

The combined market capitalization of this entire collection of stocks totals less than half the amount of just one large electric utility. Thus, these equities have benefited from demand being much greater than supply. Indeed, only two members in this sector qualify as large cap stocks. Hence, institutional investors looking to have some exposure to the industry, don't have many options. As a result, a premium has to be paid to own these shares.

In the past, yields in this segment have been much higher than that of the typical equity. Currently, many have yields that are less than the average for stocks in the *Value Line* universe. This raises the question: "Are water utility stocks still a yield play?"

Short-Term Interest Rates Keep Rising

The Federal Reserve has made no secret of its intentions to keep hiking the federal funds rate at a gradual pace through 2019 should the economy continue to be strong. The yield on a one-year Treasury bill is now about 2.6%, up from close to zero from several years ago, and 131 basis points higher in the past 12 months. Investors buying a one-year bill are getting 50 basis more than from the yield of the average stock included in the *Value Line Investment Survey*. Treasury bills come with about as little risk as possible. Thus, should rates continue trending upward, accounts seeking income (with as little uncertainty as possible), may well switch from these stocks to the fixed-income market.

America's Antiquated Water Infrastructure

According to a well-known national association of civil engineers, a good portion of our pipes and valves are in desperate need of replacement. In addition, many wastewater facilities must be upgraded to be in compliance with federal regulations. How did this situation come about? For years, both utilities and state regulators didn't want to annoy water consumers (i.e. voters) by charging higher rates. All parties are now in agreement, however, that on a comparative basis, the price of water services has not kept pace with increases for electricity and other utility bills. Over the past decade or so, water companies have been spending heavily to replace old pipelines. Much still remains to be done, though.

A Positive Regulatory Environment

None of the progress made improving water assets would be possible if state regulators and water utilities did not form constructive relationships. As regulated utilities, what these companies are permitted to earn on investments made in their systems is determined by state commissions. The current status appears to be good for customers and utilities. Investors should always stay abreast of any such changes in the regulatory climate by reading each specific report.

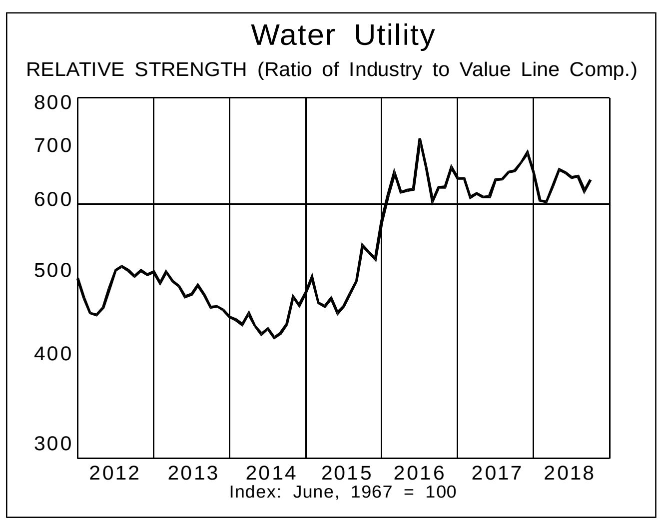
Consolidation

The publicly traded companies we follow here are actually atypical. Most water systems in the country are run by towns, cities, and states. There over 50,000 independent municipally run entities scattered throughout the country. As a result, there is a lot of inefficiencies in the market. A large company can acquire a smaller one and raise margins substantially by integrating it into existing operations. *American Water Works* and *Aqua America* are constantly absorbing multiple tuck-in acquisitions, which enables them to expand their customer bases. This trend could actually accelerate as small water districts lack the financial wherewithal required to modernize their assets.

Conclusion

Despite several stocks being favorably ranked for Timeliness, investors should proceed with caution when evaluating this group. In general, almost all have poor long-term total-returns prospects. The changing interest rate environment is also a potential problem.

James A. Flood



The Water Utility Industry carries one of the lowest Timeliness ranks of any industry under review by *Value Line*.

Prospects for higher short-term interest rates seem likely as the Federal Reserve once again raised the Fed Funds rate and indicated that more hikes are on the way. With yields on Treasury notes maturing by 2021 carrying a higher yield than that of most water utilities stocks, investors could be tempted to switch into fixed-income securities.

In general, the Tax Cuts and Jobs Act will not have a major impact on water utilities' bottom lines. All of the savings will be passed through to customers.

The fundamentals of the industry remain unchanged. Following years of low capital investments, most water utilities are spending heavily to modernized existing pipelines and other facilities.

Regulators continue to play a constructive, nonadversarial role in working with the utilities to improve the nation's water systems.

Short-Term Interest Rates Are Rising

The Federal Reserve increased the key federal funds rate by 25 basis points last month. Moreover, citing historically low unemployment, the Fed stated that it planned on increasing rates in a gradual manner through 2020. How does this impact water utilities? For starters, dividend paying stocks and fixed-income vehicles have always been in competition for income-oriented investors. Over the past decade, the extraordinary easy monetary policy (along with quantitative easing), had made dividend stocks much more appealing. This is no longer the case, however. The median yield on all dividend paying stocks in the *Value Line* universe is just about 2.0%. Individuals can now purchase an extremely secure three-month Treasury bill and get almost 2%, with as close to zero risk as possible. Moreover, should an investor be willing to extend slightly further out on the yield curve to one- or two-year Treasury notes, yields of 2.31% and 2.54% can be had. As the front end of the curve continues to rise over the next several years, utility stocks may continue to lose much of their former luster.

The Tax Cuts And Jobs Act

For most U.S.-based companies, the recent TCJA provided a nice boost to the bottom line. Water utilities were not among them, however. Knowing that regulatory commissions would mandate that the tax savings be passed on to customers, water companies simply set up reserve accounts. The surplus funds generated by the tax cut will go straight towards reducing ratepayers bills. Still, we would suggest that the TCJA is not a neutral event. That's because state regulatory commissions are given a little more flexibility when it comes to the next time a water utility in their state seeks rate relief. For example, even if a utility has a very sound reason for higher rates, but water users are already paying high prices, politicians will get push back from their constituents (i.e. voters) to keep their bills down. So, with the consumer benefiting from the tax cut, regulators will have a little more breathing room the next time a petition for higher rates is filed.

INDUSTRY TIMELINESS: 94 (of 97)

Industry Fundamentals Remain Unchanged

Following a period in which both water utilities and regulators allowed the condition of the nation's water infrastructure to deteriorate significantly, utilities have been playing catchup over the past decade or so. Thousands of miles of aging pipelines, as well as waste- water projects, are being replaced or refurbished. As a result, capital expenditures are relatively large for most members of this group. This also means that many of the balance sheets are only average, as they have had to rely upon the issuance of new debt to fund their construction projects

Another trend that continues, (particularly for two of the biggest publicly traded water utilities, *American Water Works* and *Aqua American*) is consolidation. Larger companies are acquiring smaller water districts as a means of expanding the customer base. This strategy has proven profitable to date and we expect it possibly to accelerate. Indeed, there are over 50,000 small, inefficient water districts that could be combined to extract huge cost savings.

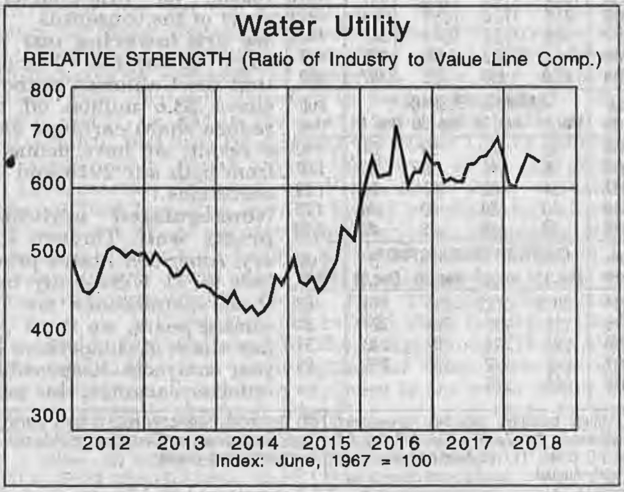
Regulation

Perhaps the best thing that water utilities have going for them is constructive regulation, as authorities realize that the nation's water systems are in a terrible state and much has to be done to fix the problem. Relations between regulators and utilities can sometimes be hostile as was the case in the electric utility industry in the 1980's and 1990's. Accounts should always keep a close eye on any change in this relationship as state commissions determine the rate of return that a regulated company can earn.

Conclusion

In general, water utility companies have done pretty well over the past few year. However, the premium that these stocks trade at is starting to seem expensive. While part of this will always be due to the scarcity value (there are only a handful of large-cap stocks in this group), the recent flattening of the front end of treasury yield curve could prove to provide investors with a better alternative.

James A. Flood



S&P Global
Market Intelligence

October 9, 2018
spglobal.com/marketintelligence

RRA Financial Focus
Utility relative performance and valuation

- After keeping pace with broad equity markets for most of 2017, the S&P 500 Utilities index sharply diverged downward from the S&P 500 late in the year as corporate tax reform efforts accelerated and ultimately succeeded. While the gap narrowed somewhat in the second quarter this year and again early in the third quarter, the S&P 500 Utilities index was slightly in negative territory for the 12 months ended Sept. 28, versus an approximately 16% gain for the S&P 500.

- Tax reform, a rising interest rate environment amid strong economic indicators, and the prospect of more robust earnings growth in the broader market appear to be among the factors driving underperformance in the traditionally defensive utility sector.

- The quadrant chart below shows how the RRA utility universe looks when comparing the P/E ratio and the estimated long-term earnings growth rate. It appears there is a concentration of electric utilities — most of which also have notable gas operations — and multi-utilities in or near the lower left quadrant, i.e., at relatively low EPS growth forecasts and relatively low forward P/E ratios. In addition, the water utilities appear to be concentrated in or near the bottom right quadrant, at relatively lower forecast EPS growth and comparatively high P/E ratio.

- However, elevated P/E valuations persist among some utility stocks, particularly small to mid-cap gas and electric utility names, with investors assigning premiums to those companies for various reasons, likely including strong financial quality, a solid earnings and dividend growth outlook, and the potential to be acquired by larger utility holding companies looking to sustain and grow earnings.

- Small and mid-cap utilities, particularly gas utilities serving smaller markets, remain the most likely takeover targets in our view. Gas LDCs have been particularly attractive to U.S. and Canadian buyers due to their rate base growth potential and higher authorized returns on equity. In its pending acquisition of Vectren Corp., CenterPoint Energy Inc. was likely lured, in part, by Vectren's aggressive capital improvement program and constructive regulatory treatment.

- Looking ahead, the Federal Reserve is expected to raise the federal funds rate one more time in 2018 and several times in 2019. Anticipated reasonably strong economic growth should help support utility stock prices, but the headwinds of rising interest rates may continue to dampen their performance compared to the broad market.

Jason Lehmann
Research Analyst

Sales & subscriptions
Sales_NorthAm@spglobal.com

Enquiries
support.mi@spglobal.com

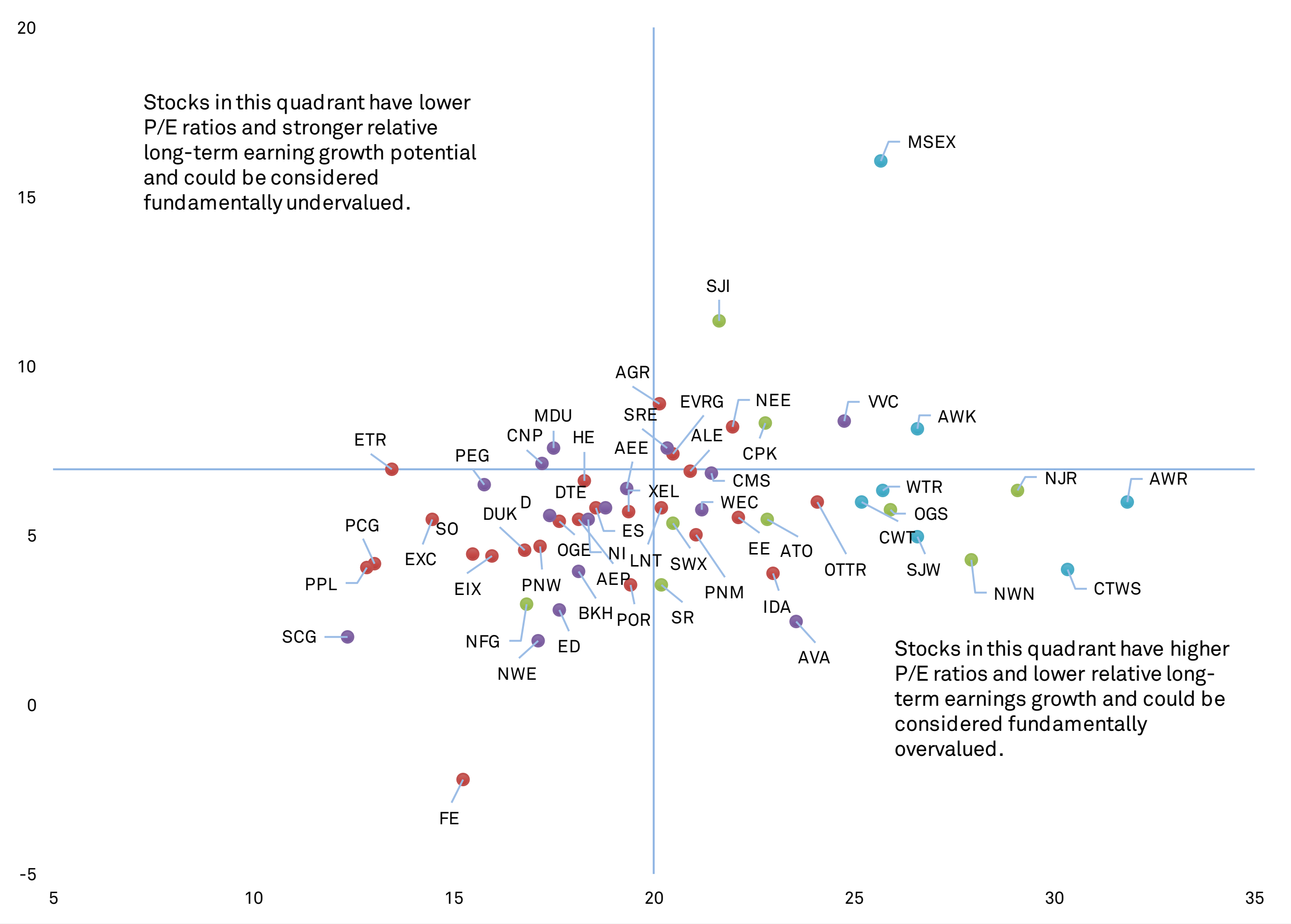
S&P Global
Market Intelligence

Financial Focus Special Report

Price versus growth – a valuation assessment

The quadrant chart below shows how the RRA utility universe looks when comparing the P/E ratio and the estimated long-term earnings growth rate. Companies in the lower right quadrant, with higher P/E multiples and lower long- term growth rates, might be considered overvalued, all other things considered equal. With a P/E of about 28x and a long-term growth estimate of 4.3%, Oregon-based Northwest Natural Gas falls into this category; however, as a smaller capitalization gas utility holding company, potential M&A interest in Northwest should not be discounted in assessing its relative overvaluation.

Valuation quadrant: EPS growth forecast vs. forward P/E ratio



As of Sept. 28, 2018.
Notes: EPS growth (vertical axis) is estimated long-term EPS growth rate.
Estimated annual EPS 2-year growth rate used when long-term rate unavailable.
P/E ratio (horizontal axis) is next 12-months P/E ratio
Orange: Electric utilities; Green: Gas utilities; Purple: Multi-utilities; Blue: Water utilties
CTWS EPS as reported.
Source: S&P Global Market Intelligence

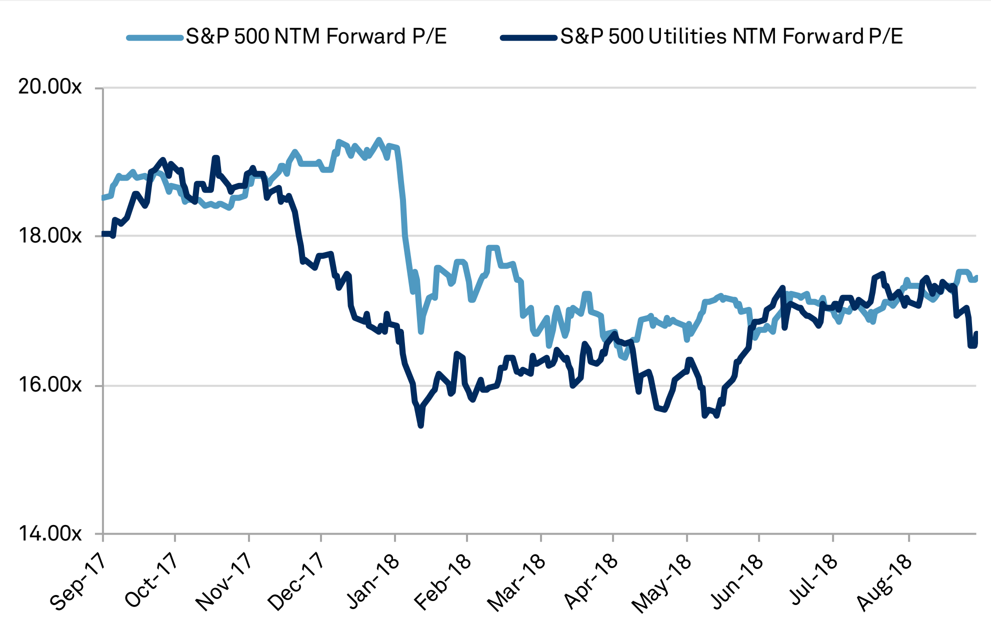
Companies with a lower valuation, i.e., P/E ratio, but stronger earnings growth potential, i.e., growth rate, in the upper left quadrant might be considered undervalued on a relative basis. For example, CenterPoint Energy Inc. has a forecast long-term earnings growth rate of 7.1% but trades below the average RRA utility group forward P/E, possibly reflecting investor caution with respect to the company's unregulated investments, including Enable Midstream, which accounted for 22% of 2017 operating earnings.

Water utilities, including American States Water Co., Connecticut Water Service Inc. and Middlesex Water Co., trade at outsized P/E valuations. Following SJW Group and Connecticut Water's announcement earlier this year of plans to merge, small-cap water utilities have experienced average trading volumes higher than their historical norms as investors have bet on who may be taken out next. For additional detail, see the Sept. 10 Financial Focus report, M&A furor roils US water utility sector.

Another possible use of RRA's valuation quadrant chart is to point to companies where there is less market confidence in the accuracy of the consensus earnings growth estimate. For example, on the surface, a company with a low P/E ratio but a high estimated EPS growth rate would be considered undervalued. However, the low P/E ratio compared to the high earnings growth estimate may be due to the market believing that actual, prospective EPS growth will be lower.

As of Sept. 28, the S&P 500 index was trading at a 17.5x next-12-months, or NTM, forward P/E ratio — down 5% from year-ago levels — versus 16.7x for the S&P 500 Utilities index, a 7% drop from September 2017. The broader RRA-covered gas and electric utility group was priced at a slight premium compared to the broader market with a forward mean NTM P/E of about 19x.

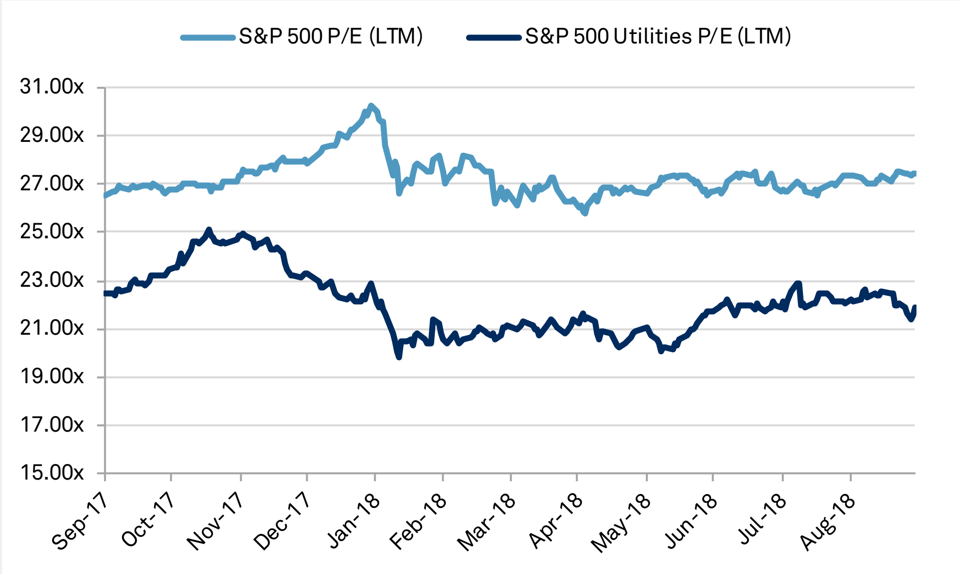
Utility NTM forward P/E trailing broader market



Through Sept. 28, 2018.
Source: S&P Capital IQ

The trailing P/E ratio on the S&P 500 at the end of September was 27.4x, up slightly from year-ago levels, while the S&P 500 Utilities trailing P/E stood at about 22x, compared with 22.4x in September 2017. By comparison, the average trailing P/E ratio for the average RRA-covered gas and electric utility grew slightly to 25.2x in September 2018 from 24.9 in September 2017.

Utility LTM P/E trailing broader market

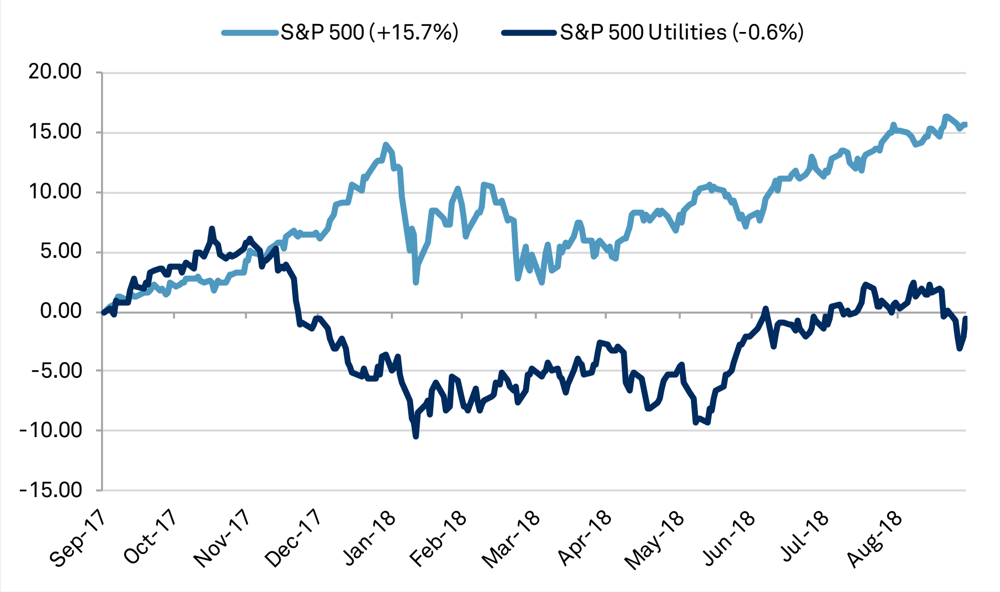


As of Sept. 28, 2018, close.
Source: S&P Capital IQ

The S&P 500 index has continued to climb, rising approximately 16% through September. Conversely, the S&P 500 Utilities Index is trading near January 2018 levels.

Despite ongoing trade disputes, the U.S. economy continues to grow steadily, fueling investor confidence. August data showed 201,000 total nonfarm payroll jobs added and an unemployment rate unchanged at 3.9%. The U.S. economy, meanwhile, expanded by 4.2% in the second quarter, and inflation was around the Fed's 2% goal.

Utilities lagging broader market price change (%)

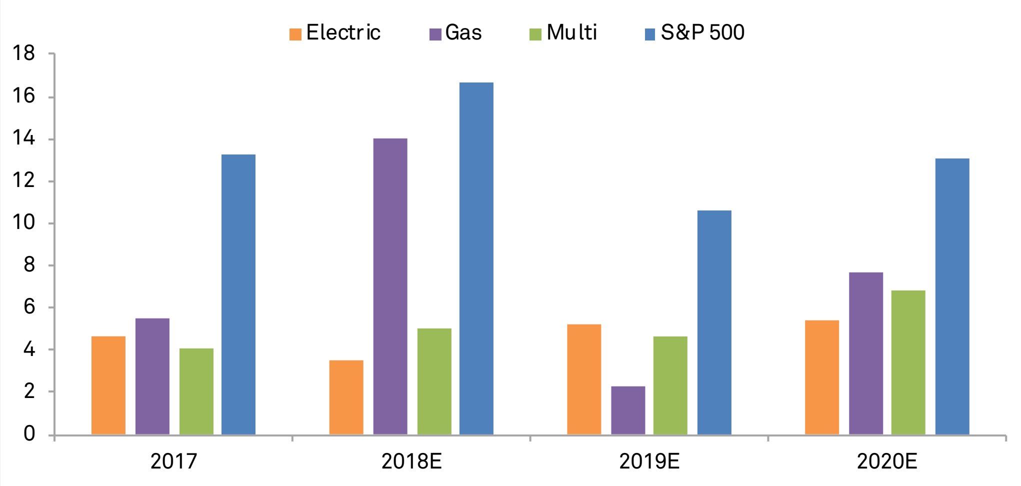


Through Sept. 28, 2018.
Source: S&P Capital IQ

Utility earnings growth versus broad market

While earnings growth for companies in the S&P 500 has been elusive in recent years, 2017 was a breakout year, with earnings climbing more than 13%. Profits for the S&P 500 index companies are expected to meaningfully outperform the electric, gas and multi-utilities sectors in the coming years, with 17% earnings growth anticipated in 2018, based on the S&P Global Market Intelligence consensus estimate. Earnings growth is expected to climb almost 11% in 2019 and a further 13% in 2020.

Utility earnings growth vs. broad market (%)



As of Sept. 28, 2018.
Source: S&P Global Market Intelligence

Within the utility sector, gas companies are expected to lead the charge in 2018, with 14% earnings growth anticipated from 2017 levels. Profit growth this year across all utilities is in part attributable to the effects of the tax reform, particularly for gas utilities for whom unregulated operations comprise a significant proportion of earnings. Unregulated utility business profits from the tax reform generally flow to the bottom line versus regulated profits, which are largely being flowed back to ratepayers. For the gas companies in RRA's coverage universe, average earnings growth in 2017 was 9.1%, slightly trailing the average EPS growth of 9.6% in the water sector but besting the EPS growth of 4.6% in the electric utility sector. For more on earnings, read: Utility EPS strong in Q2 led by electrics as weather was key sales driver. For more on estimated capital expenditures read: Utility capital spending forecasts for 2018, 2019 surge and Utility efforts to add wind generation to energy mix continue apace.

A stronger dividend yield continues to make utility stocks attractive to yield-oriented investors: the average dividend yield on an RRA covered utility is about 3.2%, compared to about 1.9% for the S&P 500, as of Sept. 28. Through September, the average utility dividend payout ratio, based on S&P Global Market Intelligence 2018 consensus earnings and dividend estimates, was 59.2%, a marginal decline from the 60.5% average payout ratio for the full year 2017.

U.S. 10-year yields crossed the 3% mark as of Sept. 21. The U.S. Federal Reserve on Sept. 26 raised its benchmark federal funds rate by 25 basis points and signaled a stronger consensus inside the U.S. central bank for another hike this year. The target range for the federal funds rate will rise to 2% to 2.25%, the Federal Open Market Committee said in a Sept. 26 statement. The rate hike marks the Fed's eighth since it began gradually increasing interest rates in December 2015 and the third in 2018.

For more on dividends read: H1'18 Dividend Review, Changes in tax laws have not altered the forward march of dividends in the utility sector. For more on utility and broad market dividend yields, see: From recession to recovery: Utility, S&P 500 and 10-year Treasury bond yields.

Sara May Bellizzi and Charlotte Cox contributed to this report.

5 Top Bank Stocks to Buy on Surging Bond Yields

Tirthankar Chakraborty
September 20, 2018

CMA WTFC BHBK UBSH FFIN

Bond yields rose on Sep 19, extending the week's climb, as investors took escalating trade related tensions in stride, and focused more on solid economic data and promising corporate outlook. The yield on the 10-year Treasury note, a benchmark for interest rates, has hit a four-month high. The Federal Reserve, in fact, has stepped up the pace of monetary tightening, with Chairman Jerome Powell vouching for a steady path of interest rate hikes.

Investors have thus exited bond proxies, including utilities, real estate, telecom and consumer staples, to name a few. Meanwhile, banks rallied on expectations to benefit from a rise in benchmark bond yield.

Bond Yields Climb North

late May. The benchmark bond yield had exceeded the mark briefly in 2013 and January 2014, which was toward the end of the bond market wipeout, better known as the "taper tantrum."

The 30-year bond yield also climbed 3.1 basis points to 3.236%, almost near a four-year high of 3.246%. Jeffrey Gundlach, chief executive officer of DoubleLine Capital and a renowned bond market expert, expects 6% on the 10-year yield by the next presidential election or the year after. He added that "a move soon to higher yields would be signaled by the 30-year closing two days in a row over 3.25%."

By the way, the 2-year note too changed hands at a decade high of 2.816%.

What's Acting in Favor of Bond Yields?

Bond yields are rising, as bond prices decline. The bond market is becoming less attractive as investors continue to load up on U.S. stocks. After all, investors are shrugging off growing trade tensions between the United States and China. And why not? President Trump did build pressure on Beijing by announcing tariffs on nearly $200 billion of Chinese products in response to "unfair trade practices." China, in the meantime, retaliated with tariffs of 5% to 10% on $60 billion worth of U.S. products. But, investors see the tariffs as less consequential than apprehended. This is because the United States did not stick to the initial 25% tariff imposition plan. China has also applied a 10% tariff on certain goods that it had earlier earmarked for a 20% levy.

Investors rather chose to focus on an improved economy and strong corporate earnings growth, which wasn't affected by weaker trade. Americans haven't been this confident about the economy in 18 years.Per the Conference Board, the consumer confidence index climbed to 133.4 in August from a revised 127.9 in July, the highest level since October 2000.

Consumers' optimism was largely driven by strength in the labor market. The current unemployment rate is now at a nearly two-decade low, while the U.S. economy has added jobs for 95 successive months in August, the longest stretch on record.

In fact, investors are getting optimistic about U.S. stocks, largely because of the encouraging outlook for corporate profits. Per the latest monthly survey of fund managers by Bank of America Merrill Lynch, there is a net allocation of 21% overweight to the U.S. equity market, the highest since January 2015. The survey also showed that a net 69% of those who polled believe that the United States has the most encouraging earnings expectation picture.

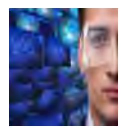
Rise in Bond Yields Boosts Banks

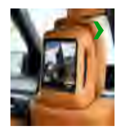
Higher bond yields can boost bank profits as they increase the spread between what banks earn by funding longer-term assets, such as loans, with shorter-term liabilities. The spread between long-term and short-term rates also expands during interest rate hikes because long-term rates tend to rise faster than short-term rates (read more: [5 Bank Stocks That Made the Most Since

Will Retailers Raise Toast to Great Holiday Sales This Year?

Most Read


Top Stock Picks for the Week


Earnings Season Is Here: 3 Tech Stocks to


New Strong Buy Stocks for October 16th

By the way, Powell told the Senate Banking Committee that "with a strong job market, inflation close to our objective, and the risks to the economy roughly balanced, the FOMC believes that – for now – the best way forward is to keep gradually raising the federal funds rate."

The Fed has raised its benchmark federal funds rate by a quarter percentage point to a range of 1.75% to 2% this year. The Fed's dot plot, in fact, indicated that policy makers predict two additional rate hikes this year for a total of four increases instead of the three planned earlier.

5 Top Bank Stocks to Buy Now

We have, thus, selected five solid bank stocks that are poised to gain from rise in bond yields. These stocks boast a Zacks Rank #1 (Strong Buy) or 2 (Buy).

Wintrust Financial Corporation (WTFC - Free Report) operates as a financial holding company in the Chicago metropolitan area, Southern Wisconsin, and Northwest Indiana. It operates in three segments: Community Banking, Specialty Finance and Wealth Management. The company has a Zacks Rank #2.

In the last 60 days, three earnings estimates moved north, while none moved south for the current year. The Zacks Consensus Estimate for earnings rose 1.3% in the same period. The company's projected earnings growth rate for the current year is 36.8%, while the Banks - Midwest industry is expected to rally 29.4%.

Comerica Incorporated (CMA - Free Report) provides various financial products and services. The company operates through three segments: Business Bank, the Retail Bank, and Wealth Management. The company has a Zacks Rank #2.

Over the last 60 days, 10 earnings estimates moved north, while none moved south for the current year. The Zacks Consensus Estimate for earnings rose 0.9% in the same period. The company's projected earnings growth rate for the current year is 49.2%, while the Banks - Major Regional industry is estimated to rise 27.2%.

Blue Hills Bancorp, Inc. (BHBK - Free Report) operates as the bank holding company for Blue Hills Bank that provides financial services to individuals, families, small to mid-size businesses, government, and non-profit organizations in Massachusetts. The company sports a Zacks Rank #1.

In the last 60 days, one earnings estimate moved up, while none moved down for the current year. The Zacks Consensus Estimate for earnings rose 8.7% in the same period. The company's projected earnings growth rate for the current year is 78.6%, while the Banks - Northeast industry is expected to grow 22%. You can see **the complete list of today's Zacks #1 Rank stocks here.**

Union Bankshares Corporation (UBSH - Free Report) operates as the bank holding company for Union Bank & Trust that provides banking and related financial services to consumers and businesses. The company has a Zacks Rank #2.

Over the last 60 days, one earnings estimate moved north, while none moved south for the current year. The Zacks Consensus Estimate for earnings rose 1.8% in the same period. The company's projected earnings growth rate for the current year is 45%, while the Banks - Southeast industry is expected to climb 31%.

First Financial Bankshares, Inc. (FFIN - Free Report) provides commercial banking products and services, primarily in Texas. The company has a Zacks Rank #2.

In the last 60 days, 2 earnings estimates moved up, while none moved down for the current year. The Zacks Consensus Estimate for earnings rose 2.3% in the same period. The company's projected earnings growth rate for the current year is 28.8%, while the Banks - Southwest industry is likely to rally 14.6%.

Will You Make a Fortune on the Shift to Electric Cars?

Here's another stock idea to consider. Much like petroleum 150 years ago, lithium power may soon shake the world, creating millionaires and reshaping geo-politics. Soon electric vehicles (EVs) may be cheaper than gas guzzlers. Some are already reaching 265 miles on a single charge.

With battery prices plummeting and charging stations set to multiply, one company stands out as the #1 stock to buy according to Zacks research.

It's not the one you think.

See This Ticker Free >>

Hide Full Article

In-Depth Zacks Research for the Tickers Above

Normally $25 each - click below to receive one report FREE:

- Comerica Incorporated (CMA) - free report >>
- Wintrust Financial Corporation (WTFC) - free report >>
- Blue Hills Bancorp, Inc. (BHBK) - free report >>
- Union Bankshares Corporation (UBSH) - free report >>
- First Financial Bankshares, Inc. (FFIN) - free report >>

More From Zacks Analyst Blog


NVR to Report Q3 Earnings: What's in Store for the Stock?


BP Midstream Announces 3rd Consecutive...


Under Armour Benefit From Growth in Digita &...

You May Like


New Strong Buy Stocks for October 16th


Top Ranked Value Stocks to Buy for October 16th


Top Ranked Growth Stocks to Buy for Octo 16th

Quick Links

Services
Account Types
Premium Services
Zacks Rank
Research
Personal Finance
Commentary
Education
Zacks Advisor Tools

My Account
Manage Account
Update Profile
Subscriptions
Preferences
Login/Password Help
Upgrade to Premium

Resources
Help
About Zacks
Disclosure
Privacy Policy
Terms of Service
Performance
Site Map
Podcasts
Earnings Calendar

Client Support
Contact Us
Share Feedback
Media
Careers
Advertise

Follow Us
Facebook
Twitter
Linkedin
RSS
You Tube

Zacks Mobile App
Download on the App Store
GET IT ON Google Play

Zacks Research is Reported On:

At the center of everything we do is a strong commitment to independent research and sharing its profitable discoveries with investors. This dedication to giving investors a trading advantage led to the creation of our proven Zacks Rank stock-rating system. Since 1988 it has more than doubled the S&P 500 with an average gain of +25.68% per year. These returns cover a period from January 1, 1988 to October 1, 2018. Zacks Rank stock-rating system returns are computed monthly based on the beginning of the month and end of the month Zacks Rank stock prices plus any dividends received during that particular month. A simple, equally-weighted average return of all Zacks Rank stocks is calculated to determine the monthly return. The monthly returns are then compounded to arrive at the annual return. Only Zacks Rank stocks included in Zacks hypothetical portfolios at the beginning of each month are included in the return calculations. Zacks Ranks stocks can, and often do, change throughout the month. Certain Zacks Rank stocks for which no month-end price was available, pricing information was not collected, or for certain other reasons have been excluded from these return calculations.

Visit performance for information about the performance numbers displayed above.

Visit www.zacksdata.com to get our data and content for your mobile app or website.

Real time prices by BATS. Delayed quotes by Sungard.

NYSE and AMEX data is at least 20 minutes delayed. NASDAQ data is at least 15 minutes delayed.

CHIEF INVESTMENT OFFICE

Capital Market Outlook

The opinions are those of the author(s) and subject to change.

MAY 29, 2018

IN THIS ISSUE

MACRO STRATEGY

The capital expenditure (CAPEX) cycle is currently experiencing a resurgence as a result of stronger global growth, rising commodity prices, lower economic policy uncertainty, declining slack in capacity utilization and stimulative fiscal policy (in the U.S.). These factors have combined to provide a large boost to corporate confidence, which should keep business spending on equipment growing at a decent clip heading into 2019. Overall, we view this is a positive backdrop for CAPEX-related technology and industrial stocks to make new highs.

GLOBAL MARKET VIEW

Stock prices have struggled to recover from the January-February drawdown, despite continuing strength in corporate earnings. We nonetheless look for cyclical sectors to continue leading the market advance as we move toward mid-year and into the second half of 2018.

THOUGHT OF THE WEEK

Political risk is now one of the significant driving forces of financial markets. This is particularly evident in Italy, where differences between politics and policy have raised a major political risk for European investors, causing Italian yields to rise sharply, and equity markets to sell off last week. However, we remain favorable on European equities despite the political hurdle in Italy, and we continue to monitor the situation.

PORTFOLIO CONSIDERATIONS

Active management of equities is favored at this point in the cycle given a normalizing interest-rate environment and a wide corporate earnings variance. We continue to favor high quality in bonds and suggest considering using commodities for a hedge on pockets of equity and fixed-income underperformance.

MACRO STRATEGY

CAPEX OUTLOOK

Jonathan W. Kozy, Senior Vice President and Senior Research Analyst

The major leading indicators of global capital spending prospects that we track have been in an upswing since the end of 2016 (Exhibit 1). In the U.S., the capital expenditure (CAPEX) cycle is experiencing a relatively stronger resurgence than the rest of the world as a result of the fiscal stimulus boost, which added to tailwinds from stronger global growth, lower economic policy uncertainty, rising commodity prices and declining slack in capacity utilization. At the same time, consumer spending and housing have been strong sources of domestic demand, and rising labor costs have increased the incentive for businesses to boost productivity. Technology-related CAPEX has led the way on this front. Elevated geopolitical risk, while often viewed as a potential headwind for business confidence, has served to keep defense spending a priority. While corporate debt is on the rise, corporate nonfinancial balance sheets do not appear to be a headwind at this stage (tax cuts helped) but are worth watching. There are also pockets of pent-up demand as a result of the domestic CAPEX recession from late 2015 to the second half of 2016. That said, there are still limitations to CAPEX at this stage of the cycle. Overall, we expect a high single-digit pace of growth for real business equipment spending over the balance of the year and into 2019. This expected pace of growth should create opportunities in CAPEX-related technology and industrial stocks.

U.S. BUSINESS CONFIDENCE SKY HIGH

The easiest way to gauge the direction and strength of CAPEX is to ask company management, and here, there is no shortage of positive data. According to the Duke CFO Global Business Outlook Survey, business confidence in the U.S. is at its highest level in its 27-year history. Looking specifically at CAPEX, executives' expectations for growth in the next 12 months surged in the first quarter to 11%. The semi-annual Institute for Supply Management (ISM) survey of capital

Data as of 05/29/2018 and subject to change.

spending plans also shows a surge since tax reform was passed in December, with both the manufacturing and non-manufacturing companies sharply raising their plans for 2018. Outside the U.S., financial executives' expectations for CAPEX in Europe, China and Japan have also improved, according to the Duke CFO Global Business Outlook Survey (Exhibit 1).

Exhibit 1: Leading Indicators Point to Solid Global CAPEX

GLOBAL CAPEX–KEY INDICATORS	2016	2017	2018
Global Real GDP Growth (%)	3.2	3.8	3.5-4.0 (E)
Duke/CFO Outlook: Expected Growth in Capital Spending 12 months (%)			
U.S.	1.4	3.2	11.0
Europe	2.7	4.8	7.0
Japan	-5.4	8.6	14.2
China	6.2	2.1	9.1
Canada: Business Outlook: Investment in Machinery & Equipment: Balance	24.0	29.0	24.0
Germany: ZEW Survey, Profit Expectations (6 months): Machinery	26.8	50.9	30.1
Japan: Small/Medium Business Survey: Equipment Production Capacity	-4.0	7.8	9.9
U.K.: BoE Agents' Survey: Investment Intentions: Manufacturing	0.1	1.1	1.5
U.K.: BoE Agents' Survey: Investment Intentions: Services	0.2	1.0	0.9
U.S. Indicators			
CEO Business Confidence Survey: Business Executive Confidence	65.0	63.0	65.0
Small business optimism: NFIB % planning CAPEX in 3 to 6 months	29.0	27.0	29.0
Economic Policy Uncertainty* (index)	257.5	149.7	147.4
Average Age Capital Stock: Private Equipment (years)	7.2	N/A	N/A
FRB: Sr. Loan Officers Survey: Banks Tightening C&I Loans	1.5	-8.5	-11.3
FRB: Sr. Loan Officers Survey: Banks Reporting Stronger Demand C&I Loans	-5.9	-11.3	-7.0
Nonfinancial Corporate Business Liquid Assets/Short-term Liabilities	48.2	51.2	N/A
Capacity Utilization: All Industry	75.7	77.3	78.0
U.S. Real Investment Spending Growth (%)–Equipment (includes IT)	-3.4	4.8	7-10 (E)
U.S. Real Investment Spending Growth (%)–Intellectual Property Products	6.3	3.9	4-6 (E)

Sources: IMF, CFO Magazine, Conference Board, BEA, FRB, NFIB, PolicyUncertainty.com/ Haver Analytics. Data as of May 29, 2018. (E) = GWIM CIO Estimate. YTD = Year to Date *Policyuncertainty.com

ACCELERATOR EFFECT GOES GLOBAL

Companies need confidence in the outlook for demand in order to pull the trigger on big ticket items, and the global backdrop has improved significantly since 2016. Recent levels of global manufacturing survey data (global purchasing managers' indexes) are consistent with an upbeat assessment of final demand fundamentals. While the acceleration in global growth may be slowing, the level of growth should be sufficient for CAPEX-related stocks to make new highs, all else being equal, in our view. A number of emerging markets are in the early stages of cyclical pickups, Japan is likely to keep its foot on the fiscal and monetary accelerators (with a greater emphasis on the former), and, in China, fiscal stimulus is coming in fits and starts to ensure the economy hits its target growth rate for overall gross domestic product (GDP). While there are some signs of fading cyclical momentum in Europe, we are not seeing signs of an imminent recession. In the end, we expect global growth to be slightly stronger in 2018 than it was in 2017. The U.S. business equipment spending cycle is one of the most globalized cycles, making the global synchronized nature of the CAPEX revival particularly beneficial.

COMMODITY REFLATION HELPS

Commodity prices are getting a boost from global growth and in turn are supporting CAPEX. After years of depressed investment levels (three years for oil and gas, seven years for mining, four years for agriculture), the recent backdrop of higher commodity prices is spurring both maintenance and expansion CAPEX in end markets that now possess more favorable economics. North American onshore investment and process automation spending, which is primarily related to oil and gas and chemicals, is an area of notable strength, driven by oil prices moving above breakeven for many producers, strong global growth generating demand for refined products and upcoming regulations, such as 2020 rules for Sulphur limits on marine fuels, expected to constrain supply.

While there is some pent-up demand in cyclical sectors, there are also areas of frothiness that are more in line with the age of the overall business cycle. Transportation-related spend, mainly in truck, for example, has been very strong, which has been a result of much higher freight rates from the very tight freight environment. A driver shortage and the implementation of electronic logging device (ELD) regulations, along with very strong domestic demand and CAPEX incentivizing tax reform, have caused a surge in truck orders, which are running well above replacement levels. We see potential for this strength to continue in the near term, given continued strength in freight, but do expect continued builds above replacement to eventually result in spend being pulled forward from out years.

From an industry perspective, technology spending has long been a strong driver of the trends in business spending on equipment, and it appears to be accelerating in 2018. CAPEX for leading tech firms is expected to grow 56% in 2018, a significant step up from prior years. This growth is partially attributable to rapid growth in hyperscale data centers as well as ever increasing demand for compute capacity, which necessitates spending on central processing units (CPUs), memory, network infrastructure, software, building infrastructure and manufacturing process equipment.

Lastly, corporate balance-sheet conditions matter, and here there are offsetting factors at work. While U.S. companies have spent the last few years taking advantage of lower interest rates and are no longer "lean and mean," they still have some spending power, and tax cuts provided a boost. As of the fourth quarter of last year, the Federal Reserve's Flow of Funds shows nonfinancial corporations had $2.49 trillion in liquid assets, an improvement to over 50% of short-term liabilities (Exhibit 1). Lending conditions have also improved for businesses, according to the Federal Reserve's (Fed) Senior Loan Officer Opinion Survey on Bank Lending Practices (Exhibit 1). The impact of the accelerated depreciation bonus and overall tax cuts is difficult to predict but could be significant, even as the overall cycle matures. The financing gap, a leading indicator of future CAPEX spending, for example, suggests spending could be higher over the next few quarters. Finally, as wage pressures grow and squeeze margins, firms should have more incentive to spend on productivity-boosting equipment, but declining margins will also make companies more vulnerable to slowdowns. Leading indicators suggest this risk is minimal, for now.

WHAT'S AN INVESTOR TO CONSIDER?

We think investors could take advantage of opportunities in end markets where the current global growth environment, commodity price backdrop and previously depressed CAPEX levels, could support a multi-year upcycle in investment spending. For upside and to move beyond current maintenance and repair investments into capacity expansions, we look for a stronger-for-longer global growth environment and a sustained upward trajectory in commodity prices that could eventually necessitate incremental capacity investments across supply chains. The inverse of this backdrop—commodity prices falling and global growth slowing—is the key downside risk, along with margin pressures from price/cost headwinds, where companies are unable to keep up with rising input costs such as raw material, labor and freight. On specific end markets, we highlight the potential for a multi-year recovery in select oil and gas (O&G)-related end markets and the continued vigorous pace of technology and commercial aerospace investments. For exposure to rebounding oil and gas CAPEX, within the energy sector we favor onshore oilfield equipment companies with leading positions in North American well completion and pumping equipment, and within the industrial sector we favor multi-industry companies with best-in-class process automation businesses that have proven technological advantages versus peers. For both of these cohorts, we prefer high-quality companies that used the recent down cycle in energy investment to improve balance sheets, invest in technology and gain market share. For technology, we look to companies that benefit from surging hyperscale data-center spending mentioned earlier. For commercial aerospace, continued above-trend growth in global flight hours supports a favorable outlook for both airplane and component manufacturers, as well as aftermarket parts suppliers.

GLOBAL MARKET VIEW

TAKING STOCK OF U.S. EQUITY SECTORS

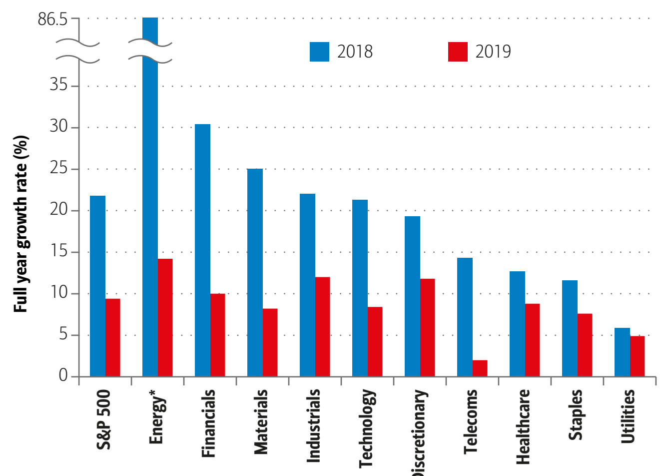
Ehiwario Efeyini, Senior Vice President and Senior Research Analyst

First-quarter earnings season for the S&P 500 is winding down, and the current 25%-plus year-on-year growth rate has been the strongest since the initial rebound from the financial crisis. Despite expectations moving higher into the start of the season, a well-above-average share of companies has exceeded analyst profit and revenue forecasts. Improving global economic activity has played a role in the earnings recovery since the growth rate troughed in early 2016, but tax policy also helped to lift results in the first quarter. An estimated $83 billion of overseas corporate cash has now been returned to the U.S., with $440 billion announced for Q1[1], while share buybacks totaled a record $178 billion in the first quarter according to S&P Dow Jones indexes—a 34% increase over Q1 2017.

Stock prices have nonetheless struggled to recover from the January-February drawdown alongside a peak in earnings momentum. Looking through the strong earnings expected in 2018, profit growth is expected to slow significantly across each of the S&P 500 sectors in 2019 (Exhibit 2), with year-on-year growth for the broad market slipping back below 10% from the first quarter of next year. This does not necessarily mean an end to the rise in prices. Sustained periods of flat or declining markets have typically occurred with outright earnings contraction, not slower earnings growth (Exhibit 3).

Exhibit 2: Expected S&P 500 Earnings Growth by Sector

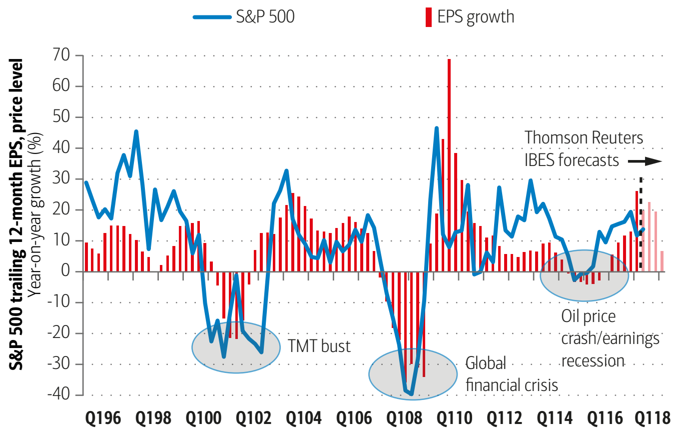
Consensus Expected EPS Growth.



*Energy consensus expectation for 2018 is 86.5%.
Source: Thomson Reuters. Data as of May 2018. Illustration is for hypothetical purposes only and based on current data and subject to change.

[1] "Capex is Coming" (Strategas Research Partners, May 11 2018).

Exhibit 3: Sustained Equity Market Declines Typically Require Outright Earnings Contraction



Light red bars are Thomson Reuters IBES forecasts for Q218 to Q119. TMT is Technology, Media and Telecommunications.
Source: Bloomberg, Thomson Reuters. Data as of May 22, 2018.

But the profit deceleration, alongside further interest rate increases and the more recent resilience in the dollar, is likely to keep the uptrend more volatile than in recent years. Since the January peak of this year, the Volatility Index (VIX) has averaged 18.5, comparable to a cycle average of 18.1 and well above the unusually low levels of 2016 (15.8) and 2017 (11.1).

We have however already begun to see cyclical sectors lead a gradual recovery from the early-year selloff. The technology and energy sectors have now regained their January peaks, with consumer discretionary also recovering more than the broad market. The defensive sectors of telecommunications and consumer staples, by contrast, have recovered the least ground and remain more than 10% off their 2018 highs. We look for cyclicals to continue leading the market advance as we move toward mid-year and into the second half, and summarize here some of our main thematic sector views.

TECHNOLOGY, ENERGY AND CONSUMER DISCRETIONARY LEADING THE CYCLICAL SECTORS

Two key elements of the U.S. tax reform should be tailwinds for the technology sector as the economic expansion extends into a tenth year. The provision for 100% expensing of investment outlays over the next five years is likely to support capital expenditure, including on IT equipment and software, while the lower rate on repatriated earnings could potentially boost technology firms more than the broad market—overseas cash holdings for the sector relative to its market capitalization are roughly double that of the broad market at around 12%. Regulatory risk has increased in the wake of the Facebook data breach, subsequent legislative hearings in Washington and Brussels, and the introduction of the new EU-wide data protection law last week. But the large digital media platforms account for 15% to 20% of the listed sector, while other groups such as hardware devices, systems software and semiconductors remain exposed to growth trends such as cloud computing, data storage and artificial intelligence. According to Cisco Systems, the volume of all stored digital data will reach 7.2 zettabytes (ZB) in 2021 from 1.8ZB in 2016 (a 32% annual growth rate). And over the same period, cloud-based data processing volumes are projected to grow at an annual rate of 22%. We also expect semiconductors to benefit from growth in connected devices and more widespread application of artificial intelligence in areas such as medical imaging, robotics and content filtering.

The surge in oil prices over recent months has helped the energy sector recover the most ground since the January-February selloff, with downstream segments such as exploration and production, equipment and services being the biggest beneficiaries. But whether or not the rise in prices can continue will depend in large part on a range of supply factors. Oil output from Venezuela has fallen by close to one million barrels per day (mbpd) since the price trough of early 2016, a trend that is likely to be reinforced through continuing underinvestment by the newly re-elected government and recently imposed U.S. sanctions. And at the same time, geopolitical uncertainty remains over the outlook for investment by European energy firms in Iran following the U.S. withdrawal from the nuclear agreement. But supply growth from the U.S. and even Organization of the Petroleum Exporting Countries (OPEC) could potentially act to restrain the price rise. Despite widely reported bottlenecks in pipeline capacity, labor and production inputs such as water and frac sand, U.S. production continues to climb. It now stands at a record 10.7 mbpd, with shale production accounting for over 50% of total output for the first time. And OPEC could also lower its targeted 1.8 mbpd production cut in light of the recent runup in prices, potentially as early as its June 22 meeting.

Within the cyclical sectors, we also see online retail leading consumer discretionary higher as it continues to take share from traditional brick and mortar segments. Internet retailers now account for a record 31% of consumer discretionary market capitalization and have been the best-performing sub-group within the S&P 500 so far this year. According to the U.S. Census Bureau, e-commerce still accounted for just 9.5% of total U.S. retail sales in the first quarter of 2018 and has remained on an uninterrupted uptrend through two recessions, from 1.0% in 2000 to 3.5% in 2007. We would expect this trend to remain a support for the group as online sales continue to grow across key categories such as media, grocery and apparel.

HIGHER-YIELDING DEFENSIVE SECTORS STRUGGLING AS INTEREST RATES RISE

With respective dividend yields of 5.7%, 3.7% and 3.1%, the telecoms, utilities and consumer staples sectors have been the three lowest-returning sectors this year. All three are likely to come under increased competition from rising interest rates as the Fed tightens further, and bond yields breach 3% beyond 10-year maturities for the first time since 2011.

For utilities and telecoms in particular, we also see a range of structural headwinds continuing to weigh on returns. Mature residential electricity sales and increasing energy efficiency continue to limit the revenue growth potential for the utilities sector, with cost headwinds coming from a range of sources. These include the need to replace existing grid infrastructure such as poles and wires, and required investment in cleaner generating capacity at the state level, even as the Environmental Protection Agency (EPA) pushes to loosen federal regulations. The falling cost of renewables and growing competition from distributed power generation should also have a negative impact on traditional utilities as costs are spread over a dwindling base of household rate payers.

Similarly for the telecoms sector, long-term pricing pressure remains on network providers in the form of growing competition from other industry incumbents and new entrants in voice, messaging and data services, while required investment outlays are also rising with the need to increase bandwidth and coverage. However, we also see potential future sources of support, particularly with valuations for the sector now among the lowest relative to their long-term averages within the S&P 500. The push for further industry consolidation could help to restore pricing power. New services such as remote security and remote energy usage management in connected homes and offices are fast-growing channels, though for now they remain too small to have a material impact on total industry revenue. And regulatory policy, if upheld in the face of a recent Senate challenge, could also provide support should weaker Federal Communications Commission (FCC) rules give more pricing power and personal data access to internet service providers.

THOUGHT OF THE WEEK

THE RETURN OF POLITICAL RISK?

John Veit, CFA®, Director and Investment Strategist

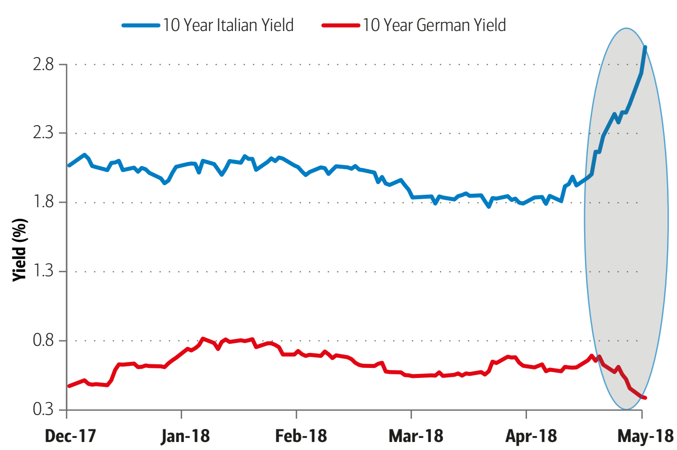
Last year, political risk generated steady white noise in financial markets but wasn't a driver of them. However, that's changed in 2018 as strong fundamentals have been outdone by politics. This is particularly evident in Italy, where differences between politics and policy have raised a major political risk for European investors. Last week, markets there experienced a sharp correction with the leak of an initial draft of a government contract that included cancellation of some public debt, although that provision was taken out of the final agreement.

There is concern that some of the progress in Italy could be undone over the next few weeks if a new government is formed around the original program negotiated between the left-wing populist Five Star Movement and the right-wing populist League, which includes a flat tax rate and the introduction of a minimum income for unemployed persons. An updated "lighter" version calls for simplification from five to two tax brackets and the introduction of a minimum income, conditional on job-seeking status and income level. This "lighter" version will still lead to deterioration of Italy's fiscal outlook and conflict with the European Union's balanced budget rules. The anticipated fiscal deterioration is one reason Italian yields spiked last week, given that Italy has one of the highest debt-to-GDP ratios across Europe (Exhibit 4).

Chartered Financial Analyst® and CFA® are registered trademarks owned by CFA Institute.

We believe it's important to separate the noise from the action: Lawmakers seem aware of Italy's narrow path and the sensitive dialogue with Europe. However, we still see scope for a communication misstep and further deterioration of the Rome-Brussels relationship. There are a lot of hurdles for Italy over the near term, and front and center is greater political risk. However, we remain favorable on European equities, despite the political hurdle in Italy, and we continue to monitor the situation.

Exhibit 4: Political Risk is Rising in Italy.



Source: Bloomberg and Chief Investment Office. Data as of May 29, 2018.
Past performance is no guarantee of future results.

MARKETS IN REVIEW

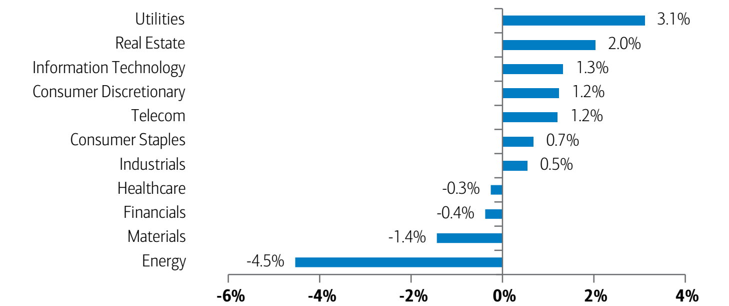
Equities

		Total Return in USD (%)		
	Level	WTD	MTD	YTD
DJIA	24,753.09	0.2	2.7	1.1
NASDAQ	7,433.85	1.1	5.3	8.2
S&P 500	2,721.33	0.3	3.0	2.6
S&P 400 Mid Cap	1,946.87	0.2	4.1	3.0
Russell 2000	1,626.93	0.0	5.6	6.4
MSCI World	2,110.80	-0.4	1.4	1.3
MSCI EAFE	2,014.52	-1.5	-0.9	-0.2
MSCI Emerging Mkts	1,136.62	0.0	-2.2	-1.3

Fixed Income[1]

		Total Return in USD (%)		
	Yield (%)	WTD	MTD	YTD
Corporate & Government	3.23	0.8	0.2	-2.3
Treasury Bills	1.91	0.0	0.1	0.6
Treasury Notes and Bonds	2.73	0.8	0.2	-1.7
Agencies	2.74	0.5	0.3	-0.9
Municipals	2.74	0.4	0.7	-0.8
U.S. Investment Grade	3.29	0.7	0.2	-2.0
International	3.94	0.8	0.1	-3.1
High Yield	6.39	0.0	0.0	-0.2

S&P 500 Sector Returns (For the week ending 5/25/18)



Commodities & Currencies

		Total Return in USD (%)		
	Level	WTD	MTD	YTD
Bloomberg Commodity	186.83	0.6	1.6	3.8
WTI Crude $/Barrel[2]	67.88	-4.8	-1.0	12.3
Gold Spot $/Ounce[2]	1,301.70	0.7	-1.0	-0.1

Level	Current	Prior Week End	Prior Month End	2017 Year End
EUR/USD	1.17	1.18	1.21	1.20
USD/JPY	109.41	110.78	109.34	112.69

Source: Bloomberg, Factset. [1] Bloomberg Barclays Indices. [2] Spot price returns. All data as of the 5/25/18 close. **Past performance is no guarantee of future results.**

Asset Class Weightings (as of 5/9/18)

	Negative		Neutral		Positive
Global Equities				●	
U.S. Large Cap Growth				●	
U.S. Large Cap Value				●	
U.S. Small Cap Growth			●		
U.S. Small Cap Value			●		
International Developed				●	
Emerging Markets				●	
Global Fixed Income		●			
U.S. Governments		●			
U.S. Mortgages		●			
U.S. Corporates			●		
High Yield		●			
U.S. IG Tax Exempt			●		
U.S. HY Tax Exempt		●			
International Fixed Income	●				
Alternative Investments*	see CIO Asset Class Views				
Hedge Funds			●		
Private Equity			●		
Real Assets			●		
Cash	We are neutral				

* Many products that pursue Alternative Investment strategies, specifically Private Equity and Hedge Funds, are available only to pre-qualified clients.

Economic and Market Ranges (as of 5/29/18)

	Q2 2017	Q3 2017	Q4 2017E	Q1 2018E	2016	2017E	2018E
Real global GDP (% y/y annualized)					3.2	3.8	3.5 – 4.0
Real U.S. GDP (% q/q annualized)	3.1	3.2	2.9	2.3	1.5	2.3	2.5 – 3.5
CPI inflation (% y/y)*	1.9	2.1	2.1	2.1	1.3	2.1	2 – 3
Core CPI inflation (% y/y)*	2.1	2.0	1.8	1.8	2.2	1.8	2 – 3
Unemployment rate, period average (%)	4.4	4.3	4.1	4.1	4.9	4.4	3.9
Fed funds rate, end period (%) **	1.12	1.12	1.37	1.63	0.62	1.37	1.87 – 2.37
10-year Treasury, end period (%)	2.31	2.33	2.41	2.74	2.45	2.41	2.87 – 3.38
S&P 500, end period	2423	2519	2674	2641	2239	2674	2800-3000
S&P operating earnings ($/share)	33	32	38	37	119	129 – 138	148 – 158
U.S. dollar/euro, end period	1.14	1.18	1.2	1.23	1.05	1.2	1.18 – 1.28
Japanese yen/U.S. dollar, end period	112	113	113	106	117	113	105 – 115
Oil ($/barrel), end period	46	52	60	65	54	60	65 – 85

The average quarterly percent growth for the current calendar year divided by the average quarterly percent growth for the previous calendar year, annualized (unless stated otherwise). E = Estimate.

* Latest 12-month average over previous 12-month average

** Fed funds rate, end period based on market indications.

Past performance is no guarantee of future results. There can be no assurance that the forecasts will be achieved.

Economic or financial forecasts are inherently limited and should not be relied on as indicators of future investment performance.

Source: Global Wealth & Investment Management Investment Strategy Committee.

Index Definitions

Securities indexes assume reinvestment of all distributions and interest payments. Indexes are unmanaged and do not take into account fees or expenses. It is not possible to invest directly in an index.

Indexes are all based in dollars.

Dow Jones Industrial Average is a price-weighted measure of 30 U.S. blue-chip U.S. companies. The index covers all industries except transportation and utilities.

NASDAQ Composite Index is a broad-based capitalization-weighted index of stocks in all three NASDAQ tiers: Global Select, Global Market and Capital Market. The index was developed with a base level of 100 as of February 5, 1971.

S&P 400 Mid Cap Index is representative of 400 stocks in the mid-range sector of the domestic stock market, representing all major industries.

S&P 500 Index includes a representative sample of 500 leading companies in leading industries of the U.S. economy. Although the index focuses on the large-cap segment of the market, with approximately 75% coverage of U.S. equities, it is also an ideal proxy for the total market.

S&P Small Cap 600 measures the small-cap segment of the U.S. equity market. The index is designed to track companies that meet specific inclusion criteria to ensure that they are liquid and financially viable.

CBOE Volatility Index (VIX): The CBOE Volatility Index, known by its ticker symbol VIX, is a popular measure of the stock market's expectation of volatility implied by S&P 500 index options, calculated and published by the Chicago Board Options Exchange.

Important Disclosures

Investing involves risk, including the possible loss of principal. No investment program is risk-free, and a systematic investing plan does not ensure a profit or protect against a loss in declining markets. Any investment plan should be subject to periodic review for changes in your individual circumstances, including changes in market conditions and your financial ability to continue purchases.

Economic or financial forecasts are inherently limited and should not be relied on as indicators of future investment performance.

It is not possible to invest directly in an index.

Asset allocation, diversification, dollar cost averaging and rebalancing do not ensure a profit or protect against loss in declining markets. Dollar cost averaging involves continual investment in securities regardless of fluctuating price levels; you should consider your willingness to continue purchasing during periods of high or low price levels.

Past performance is no guarantee of future results.

Investing in fixed-income securities may involve certain risks, including the credit quality of individual issuers, possible prepayments, market or economic developments and yields and share price fluctuations due to changes in interest rates. When interest rates go up, bond prices typically drop, and vice versa. Income from investing in municipal bonds is generally exempt from Federal and state taxes for residents of the issuing state. While the interest income is tax-exempt, any capital gains distributed are taxable to the investor. Income for some investors may be subject to the Federal Alternative Minimum Tax (AMT).

Investments focused in a certain industry may pose additional risks due to lack of diversification, industry volatility, economic turmoil, susceptibility to economic, political or regulatory risks and other sector concentration risks.

Investments in real estate securities can be subject to fluctuations in the value of the underlying properties, the effect of economic conditions on real estate values, changes in interest rates, and risks related to renting properties, such as rental defaults.

Nonfinancial assets, such as closely-held businesses, real estate, oil, gas and mineral properties, and timber, farm and ranch land, are complex in nature and involve risks including total loss of value. Special risk considerations include natural events (for example, earthquakes or fires), complex tax considerations, and lack of liquidity. Nonfinancial assets are not suitable for all investors. Always consult with your independent attorney, tax advisor, investment manager, and insurance agent for final recommendations and before changing or implementing any financial, tax, or estate planning strategy.

Investments in tangible assets are highly volatile and are speculative. There are special risks associated with an investment in commodities, including market price fluctuations, regulatory changes, interest rate changes, credit risk, economic changes, and the impact of adverse political or financial factors.

Alternative Investments such as private equity funds, can result in higher return potential but also higher loss potential. Changes in economic conditions or other circumstances may adversely affect your investments. Before you invest in alternative investments, you should consider your overall financial situation, how much money you have to invest, your need for liquidity, and your tolerance for risk.

This material was prepared by the Global Wealth & Investment Management Chief Investment Office (GWIM CIO) and is not a publication of BofA Merrill Lynch Global Research. The views expressed are those of the GWIM CIO only and are subject to change. This information should not be construed as investment advice. It is presented for information purposes only and is not intended to be either a specific offer by any Merrill Lynch or U.S. Trust entity to sell or provide, or a specific invitation for a consumer to apply for, any particular retail financial product or service that may be available.

Global Wealth & Investment Management (GWIM) is a division of Bank of America Corporation. Merrill Lynch Wealth Management, Merrill Edge®, U.S. Trust, and Bank of America Merrill Lynch are affiliated sub-divisions within GWIM. The GWIM Chief Investment Office (CIO) provides investment solutions, portfolio construction advice and wealth management guidance.

Neither Merrill Lynch nor any of its affiliates or financial advisors provide legal, tax or accounting advice. You should consult your legal and/or tax advisors before making any financial decisions.

The investments discussed have varying degrees of risk. Some of the risks involved with equities include the possibility that the value of the stocks may fluctuate in response to events specific to the companies or markets, as well as economic, political or social events in the U.S. or abroad. Bonds are subject to interest rate, inflation and credit risks. Investments in high-yield bonds may be subject to greater market fluctuations and risk of loss of income and principal than securities in higher rated categories. Investments in foreign securities involve special risks, including foreign currency risk and the possibility of substantial volatility due to adverse political, economic or other developments. These risks are magnified for investments made in emerging markets. Investments in a certain industry or sector may pose additional risk due to lack of diversification and sector concentration. Investments in real estate securities can be subject to fluctuations in the value of the underlying properties, the effect of economic conditions on real estate values, changes in interest rates, and risk related to renting properties, such as rental defaults. There are special risks associated with an investment in commodities, including market price fluctuations, regulatory changes, interest rate changes, credit risk, economic changes and the impact of adverse political or financial factors. Income from investing in municipal bonds is generally exempt from federal and state taxes for residents of the issuing state. While the interest income is tax exempt, any capital gains distributed are taxable to the investor. Income for some investors may be subject to the federal alternative minimum tax (AMT).

 AR7W6YJD

Merrill Lynch
Bank of America Corporation

147 FERC ¶ 61,234
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group

Docket No. EL11-66-001

v.

Bangor Hydro-Electric Company; Central Maine Power Company; New England Power Company d/b/a National Grid; New Hampshire Transmission LLC d/b/a NextEra; NSTAR Electric and Gas Corporation; Northeast Utilities Service Company; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; Vermont Transco, LLC

OPINION NO. 531

ORDER ON INITIAL DECISION

Issued: June 19, 2014

147 FERC ¶ 61,234
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Acting Chairman;
Philip D. Moeller, John R. Norris,
and Tony Clark.

Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group

Docket No. EL11-66-001

v.

Bangor Hydro-Electric Company; Central Maine Power Company; New England Power Company d/b/a National Grid; New Hampshire Transmission LLC d/b/a NextEra; NSTAR Electric and Gas Corporation; Northeast Utilities Service Company; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; Vermont Transco, LLC

OPINION NO. 531

ORDER ON INITIAL DECISION

(Issued June 19, 2014)

Table of Contents

1. This order addresses briefs on and opposing exceptions to an Initial Decision issued on August 6, 2013 by the presiding Administrative Law Judge (Presiding Judge) in the captioned proceeding.[1] The Initial Decision set forth the Presiding Judge's findings concerning a complaint filed pursuant to section 206 of the Federal Power Act (FPA)[2] challenging the New England Transmission Owners' (NETOs)[3] base return on equity (ROE) reflected in ISO New England Inc.'s (ISO-NE) open access transmission tariff (OATT). In this order, we affirm the Initial Decision in part, reverse the Initial Decision in part, announce a new approach we will use for determining the base ROE for public utilities, and establish a paper hearing to allow the participants an opportunity to submit briefs on a limited issue regarding application of this new ROE approach to this proceeding. We also change our practice on post-hearing ROE adjustments.

I. <u>Background</u>

2. The NETOs recover their transmission revenue requirements through formula rates included in ISO-NE's OATT.[4] The revenue requirements for Regional Network Service[5] and Local Network Service[6] that the NETOs provide are calculated using the same single base ROE. On October 31, 2006, the Commission, in Opinion No. 489, established the base ROE at 11.14 percent, which consisted of an initial base ROE of 10.4 percent plus an upward adjustment of 74 basis points to account for changes in

---

[1] *Martha Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, 144 FERC ¶ 63,012 (2013) (Initial Decision).

[2] 16 U.S.C. § 824e (2012).

[3] The NETOs include Bangor Hydro-Elec. Co.; Cent. Me. Power Co.; New England Power Co. d/b/a Nat'l Grid; N.H. Transmission LLC d/b/a NextEra; NSTAR Elect. & Gas Corp.; Ne. Utilities Serv. Co.; United Illuminating Co.; Unitil Energy Systems, Inc. and Fitchburg Gas & Elec. Light Co.; and Vt. Transco, LLC.

[4] ISO-NE's OATT is section II of ISO-NE's Transmission, Markets, and Services Tariff (Tariff). *See* ISO-NE, Tariff, § II.

[5] Regional Network Service is the transmission service over the pool transmission facilities described in Part II.B of the OATT. ISO-NE, Tariff, § I.2 (50.0.0); *see also* ISO-NE, Tariff, § II.B Regional Network Service (0.0.0), *et seq.*

[6] Local Network Service is the network service provided under Schedule 21 and the Local Service Schedules of ISO-NE's OATT. ISO-NE, Tariff, § I.2 (50.0.0); *see also* ISO-NE, Tariff, Schedule 21 Local Service (1.0.0), *et seq.*

capital market conditions that took place between the issuance of the Administrative Law Judge's initial decision in that proceeding and the issuance of Opinion No. 489,[7] as reflected in U.S. Treasury bond yields during that time period.

3. On September 30, 2011, the Complainants[8] filed a complaint alleging that the NETOs' 11.14 percent base ROE is unjust and unreasonable because capital market conditions have significantly changed since that base ROE was established in 2006. The Complainants argued that the bubble in the U.S. housing market, the subsequent financial crisis and economic recession, and the fiscal and monetary policies of the U.S. government have caused a "flight to quality"[9] in the capital markets. The Complainants contended that these market conditions have lowered bond yields and, as a result, capital costs for utilities.[10] The Complainants argued that, as a result, the NETOs' 11.14 percent base ROE now exceeds the level necessary to satisfy the Supreme Court's standards in *Bluefield*[11] and *Hope*.[12] The Complainants asserted that, based on a discounted cash flow (DCF) analysis conducted by their expert witness, the just and reasonable base ROE for the NETOs should not exceed 9.2 percent.

---

[7] *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006) *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarification*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom. Conn. Dep't of Pub. Util. Control v. FERC*, 593 F.3d 30 (2010).

[8] Complainants include Martha Coakley, Mass. Attorney Gen.; Conn. Pub. Utilities Regulatory Auth.; Mass. Dept. of Pub. Utilities; N.H. Pub. Utilities Comm'n; Conn. Office of Consumer Counsel; Me. Office of the Pub. Advocate; George Jepsen, Conn. Attorney Gen.; N.H. Office of Consumer Advocate; R.I. Div. of Pub. Utilities and Carriers; Vt. Dept. of Pub. Serv.; Mass. Mun. Wholesale Elec. Co.; Associated Indus. of Mass.; the Energy Consortium; Power Options, Inc.; and the Indus. Energy Consumer Group.

[9] The "flight to quality" refers to investors seeking low-risk investment vehicles.

[10] Complaint, Ex. C-1 at 5-12.

[11] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) (*Bluefield*).

[12] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*).

4. On May 3, 2012, the Commission issued an order on the complaint, establishing hearing and settlement judge procedures.[13] The Hearing Order also set a refund effective date of October 1, 2011. The hearing commenced on May 6, 2012 and was completed on May 10, 2013.[14] In accordance with the hearing's procedural schedule, the participants each first submitted an ROE analysis,[15] based on data from a 6-month study period in 2012,[16] and then filed an updated ROE analysis, using the same DCF methodology that each participant used in its initial analysis but with data based on the 6-month study period from October 2012 through March 2013.

5. On August 6, 2013, the Presiding Judge issued the Initial Decision, finding the NETOs' current 11.14 percent base ROE to be unjust and unreasonable.[17] The Presiding Judge adopted the DCF methodology used by the NETOs and found that it is appropriate to establish two different base ROEs in this proceeding—one for the 15-month refund period from October 1, 2011 (i.e., the refund effective date) to December 31, 2012, and one for the prospective period commencing when the Commission issues its order setting the going-forward base ROE. Thus, the Presiding Judge considered two separate DCF analyses relying on overlapping data from each period, the first using data from May 2012 through October 2012 and the second using data from October 2012 through March 2013. The Presiding Judge found the just and reasonable base ROE for the refund period to be 10.6 percent and the just and reasonable base ROE for the prospective period to be 9.7 percent.[18]

---

[13] *Martha Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, 139 FERC ¶ 61,090 (2012) (Hearing Order).

[14] The parties conducted settlement negotiations but reached an impasse, leading to termination of the settlement procedures in August 2012. Initial Decision, 144 FERC ¶ 63,012 at P 28.

[15] The following expert witnesses submitted ROE analyses: Dr. William E. Avera, for the NETOs; Ms. Sabina U. Joe, for Trial Staff; Dr. John Wilson, for the EMCOS; and Dr. Randall Woolridge, for the Complainants.

[16] Due to the different due dates for the parties' initial briefs, which ranged from October 2012 to January 2013, each party's initial ROE analysis was based on a different 6-month period in 2012.

[17] Initial Decision, 144 FERC ¶ 63,012 at P 544.

[18] *Id.*

6. The Complainants, Eastern Massachusetts Consumer Owned Systems (EMCOS),[19] the NETOs, and Trial Staff each filed briefs on and opposing exceptions to the Initial Decision.

II. Overview of the Commission's Rulings in this Order

7. In this order, we (1) change our approach on the DCF methodology to be applied in public utility rate cases, (2) apply that approach to the facts of this proceeding to determine the NETOs' base ROE, (3) institute a paper hearing and reopen the record to provide the participants an opportunity to submit briefs on an issue regarding the application of this new DCF approach to the facts of this proceeding, and (4) change our practice on post-hearing ROE adjustments.

8. As discussed in detail below, the Commission has historically applied different DCF methodologies in determining the ROE for public utilities and natural gas and oil pipelines. While there are multiple differences between the two DCF methodologies, the most fundamental difference is that the methodology applied to natural gas and oil pipelines (i.e., the two-step DCF methodology) considers long-term growth projections in estimating a company's cost of equity, whereas the methodology applied to public utilities (i.e., the one-step DCF methodology) considers only short-term growth projections. Based on a review of those methodologies and changes to the electric utility industry since the Commission last considered its electric industry DCF policy, we conclude that it is now appropriate to use the same model for the electric industry as the Commission has used for the natural gas and oil pipeline industries—i.e., use the two-step DCF methodology. We also make a tentative finding that the required long-term growth projection should be based on projected long-term growth in gross domestic product (GDP), but we establish a paper hearing to permit participants to present evidence on that issue.

9. After setting forth our new approach to the electric industry DCF analysis, we then apply the two-step DCF methodology to the facts of this proceeding to produce a proxy group and zone of reasonableness for determining the NETOs' base ROE. While no party proposed using the two-step DCF methodology in this proceeding, there is considerable overlap in the issues that arise under either type of DCF analysis. We find that the NETOs' starting proxy group is consistent with Commission precedent and the record contains all the financial data necessary to conduct a DCF analysis of that proxy group using the two-step DCF methodology, except for a projection of long-term GDP

---

[19] EMCOS filed a motion to intervene out-of-time on Oct. 1, 2012, and the Presiding Judge granted the motion on Oct. 4, 2012.

growth.[20] Therefore, in order to complete a DCF analysis of the proxy group under the two-step DCF method, we take official notice of the necessary GDP growth projections. Our DCF analysis produces a zone of reasonableness of from 7.03 percent to 11.74 percent. We find it appropriate, based on record evidence, to place the NETOs' base ROE halfway between the midpoint of the zone of reasonableness and the top of that zone. This results in an ROE for the NETOs of 10.57 percent.

10. However, because the participants have not had an opportunity to present evidence on long-term growth rate estimates in this proceeding, we establish a paper hearing and reopen the record to provide that opportunity. Accordingly, our finding concerning the specific numerical just and reasonable ROE for the NETOs is subject to the outcome of the paper hearing on the appropriate long-term growth projection to be used in the two-step DCF methodology.

11. Lastly, based on the record in this proceeding and the economic trends since 2008 more generally, we change our past practice on post-hearing ROE adjustments. Specifically, we end our practice of updating the ROE based on changes in U.S. Treasury bond yields during the proceeding, in light of our shift to the two-step DCF methodology and mounting evidence that U.S. Treasury bond yields are not necessarily a reliable one-for-one indicator of changes in investor-required returns.

12. On balance, we find that our actions in this order, including the shift to the use of the two-step DCF methodology, the placement of the NETOs' base ROE at the midpoint of the upper half of the zone of reasonableness, and the elimination of the post-hearing adjustment based on U.S. Treasury bonds, taken together produce a base ROE that reasonably balances investor and consumer interests consistent with *Hope* and *Bluefield* and allow just and reasonable rates for consumers and transmission owners.[21]

III. Adopting the Two-Step, Constant Growth DCF Methodology for Public Utilities

13. The Complaint filed in this proceeding argues that, based on the DCF methodology the Commission currently uses in public utility rate cases, the existing base

[20] We adopt the work papers provided by the NETOs' witness, Dr. Avera, including his stock prices, dividends, and IBES short-term growth projections, as the appropriate inputs for the dividend yield calculations using the two-step DCF methodology.

[21] *See, e.g.*, *Hope*, 320 U.S. at 603.

ROE for electric transmission service is too high, and thus unjust and unreasonable.[22] Other pending complaints before the Commission echo the same theme.[23] At the same time, the NETOs have assailed the Commission's existing electric DCF methodology as failing to produce adequate returns.[24] In light of the concerns raised by both transmission customers and transmission owners, the Commission has reviewed its DCF analysis used in determining public utility ROEs. For the reasons discussed below, we find that the ROE in this proceeding, as well as in future public utility cases,[25] should be based on the same DCF methodology the Commission has used in natural gas pipeline and oil pipeline cases for many years—the two-step, constant growth DCF methodology, or two-step DCF methodology.

---

[22] Complaint at 25-26.

[23] *See, e.g.*, Environment Northeast, *et al.*, Complaint, Docket No. EL13-33-000 (filed Dec. 27, 2012); Seminole Electric Cooperative, Inc. and Florida Municipal Power Authority, Complaint, Docket No. EL12-39-000 (filed Feb. 29, 2012); Seminole Electric Cooperative, Inc. and Florida Municipal Power Authority, Complaint, Docket No. EL13-63-000 (filed May 13, 2013); Golden Spread Electric Cooperative, Inc., Complaint, Docket No. EL12-59-000 (filed Apr. 20, 2012); Golden Spread Electric Cooperative, Inc., Complaint, Docket No. EL13-78-000 (filed Jul. 19, 2013); Grand Valley Rural Power Lines, *et al.*, Complaint, Docket No. EL12-77-000 (filed Jun. 21, 2012); Grand Valley Rural Power Lines, *et al.*, Complaint, Docket No. EL13-86-000 (filed Aug. 30, 2013); New York Association of Public Power, Complaint, Docket No. EL12-101-000 (filed Sept. 11, 2012); Municipal Electric Association of New York, Complaint, Docket No. EL13-16-000 (filed Nov. 2, 2012); New York Association of Public Power, Complaint, Docket No. EL14-29-000 (filed Feb. 6, 2014); Delaware Division of the Public Advocate, *et al.*, Complaint, Docket No. EL13-48-000 (filed Feb. 27, 2013); Frankford Electric & Water Plant Board, *et al.*, Complaint, Docket No. EL14-5-000 (filed Oct. 17, 2013); and ABATE, *et al.*, Complaint, Docket No. EL14-12-000 (filed Nov. 12, 2013).

[24] *See, e.g.*, NETOs Brief on Exceptions at 36..

[25] We consider that this group includes all currently pending ROE-related complaint cases in which the Commission has not issued a final order. In cases which have already been set for hearing, the Presiding Judge should modify the procedural schedule as necessary to provide the participants an opportunity to present evidence relevant to the application of the two-step DCF methodology.

14. For over 30 years, the Commission has based ROEs on the rate of return required by investors to invest in a company – otherwise known as the capital attraction rate of return, or the market cost of equity capital. Over this period, the Commission has relied primarily on the DCF model to provide an estimate of the investors' required rate of return.[26] The underlying premise of the DCF model is that an investment in common stock is worth the present value of the infinite stream of dividends discounted at a market rate commensurate with the investment's risk.[27]

15. With simplifying assumptions, the formula for the DCF model reduces to: P = D/k-g, where "P" is the price of the common stock, "D" is the current dividend, "k" is the discount rate (or investors' required rate of return), and "g" is the expected growth rate in dividends. For ratemaking purposes, the Commission rearranges the DCF formula to solve for "k", the discount rate, which represents the rate of return that investors require to invest in a company's common stock, and then multiplies the dividend yield by the expression (1+.5g) to account for the fact that dividends are paid on a quarterly basis. Multiplying the dividend yield by (1+.5g) increases the dividend yield by one half of the growth rate and produces what the Commission refers to as the "adjusted dividend yield." The resulting formula is known as the constant growth DCF model and can be expressed as follows: k=D/P (1+.5g) +g.

16. While the DCF model has been employed for decades, it has nonetheless continued to generate controversy. In response, the Commission has, over the years, made changes in its implementation of the model with respect to the industries it regulates. In making these changes, the Commission's application of the DCF model to public utilities now diverges significantly from the Commission's application of the model to natural gas and oil pipelines. As discussed in more detail below, the Commission uses a one-step DCF methodology for public utilities and a two-step DCF methodology for natural gas and oil pipelines. The difference in the naming conventions for the two methodologies stems from the growth rate projections used in each: the one-

---

[26] The Commission first took cognizance of the DCF methodology in public utility cases as far back as the 1970's. *See, e.g., Minn. Power and Light Co.*, 3 FERC ¶ 61,045, at 61,132-33 (1978) ("We are interested in forward looking analyses of the market's required rates of return. The Commission seeks to have before it estimates of the opportunity cost of equity capital in capital markets to use in making rate of return determinations. Market oriented techniques, including the DCF approach, are useful in this regard.").

[27] *See, e.g., Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289, 293 (D.C. Cir. 2001) (*CAPP v. FERC*).

step DCF methodology is based only on short-term growth projections, while the two-step DCF methodology considers both short-term and long-term growth projections.

A. Two-Step DCF Methodology

17. The Commission developed the two-step DCF methodology used for determining the cost of capital for individual gas and oil pipelines in a series of orders during the mid-1990s. Under that methodology, the Commission determines a single cost of equity estimate for each member of a proxy group. For the dividend yield component of the DCF model, the Commission derives a single, average dividend yield based on the indicated dividend and the average of the monthly high and low stock prices over a six-month period.[28] The Commission uses a two-step procedure for determining the constant dividend growth component of the model, averaging short-term and long-term growth estimates. Security analysts' five-year forecasts for each company in the proxy group, as published by the Institutional Brokers Estimate System (IBES), are used for determining growth for the short term; earnings forecasts made by investment analysts are considered to be the best available estimates of short-term dividend growth because they are likely relied on by investors when making their investment decisions.[29] Long-term growth is based on forecasts of long-term growth of the economy as a whole, as reflected in GDP.[30] The short-term forecast receives a two-thirds weighting and the long-term forecast receives a one-third weighting in calculating the growth rate in the DCF model.[31]

---

[28] *See, e.g., Portland Natural Gas Transmission Sys.*, Opinion No. 510, 134 FERC ¶ 61,129, at PP 232-34 (2011).

[29] *See, e.g., Transcon. Gas Pipe Line Corp.*, Opinion No. 414-B, 85 FERC ¶ 61,323, at 62,269 & n.34 (1998) (which cites an article entitled "Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return" in *Financial Management*, Spring 1986, pages 58-67); *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048, at PP 73-77 (2008) (*Proxy Group Policy Statement*).

[30] *Nw. Pipeline Corp*., Opinion No. 396-B, 79 FERC ¶ 61,309, at 62,383 (1997) *Williston Basin Interstate Pipeline Co.*, 79 FERC ¶ 61,311, at 62,389 (1997), *aff'd in relevant part sub nom. Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54, 57 (D.C. Cir. 1999).

[31] *Transcon. Gas Pipe Line Corp*., Opinion No. 414-A, 84 FERC ¶ 61,084, at 61,423-24, *reh'g denied*, Opinion No. 414-B, 85 FERC ¶ 61,323, at 62,266-70 (1998), *aff'd*, *CAPP v. FERC*, 254 F.3d 289.

18. The Commission first required a two-step method for determining constant growth of dividends in natural gas pipeline cases in 1994, in *Ozark Gas Transmission System*, 68 FERC ¶ 61,032 (1994) (*Ozark*). In *Ozark*, the Commission held that the constant growth DCF model that the Commission uses requires consideration of long-term growth projections. The Commission explained:

> In the constant growth DCF model used by both parties in this proceeding, dividends are expected to grow indefinitely at the rate of (g). The indefinite future used by the DCF model is 50 years or more. . . . While we concede that it is more difficult to project growth for many years from the present time, we conclude that a projection limited to five years, with no evidence of what is anticipated beyond that point, is not consistent with the DCF model and cannot be relied on in a DCF analysis.[32]

19. The Commission also pointed out that, in its 1983 decision adopting the constant growth DCF model for gas pipeline cases, the Commission had cautioned that "we cannot simply adopt, without further consideration, calculations of past dividend growth or projections by investment advisory services of growth for relatively short periods of years into the future."[33] Thus, the Commission in *Ozark* reversed the Presiding Judge's sole reliance on five-year growth projections for the DCF analysis, finding that "the five-year projections are not of themselves incorrect, but merely limited to too brief a time period to meet the requirements of the DCF model."[34]

20. Following *Ozark*, debate ensued in natural gas pipeline cases over the best way to estimate the long-term growth of pipeline dividends. In Opinion No. 396-B, issued in 1997, the Commission found that none of the proposed natural gas industry-specific projections of long-term growth were reliable.[35] Instead, the Commission held that the long-term growth in the United States economy as a whole, as measured by GDP, is the

---

[32] *Ozark*, 68 FERC at 61,105. The Commission chose 50 years to represent the indefinite future because the present value of a one-dollar dividend received 50 years in the future and discounted at 12 percent is less than one cent. *Id.* at n.32.

[33] *Consol. Gas Supply Corp.*, 24 FERC ¶ 61,046, at 61,146 (1983).

[34] *Ozark*, 68 FERC at 61,107.

[35] The proposed industry-specific projections included projections of the growth of natural gas consumption and the growth of natural gas prices.

most reasonable measure to use as the long-term growth measure for a DCF analysis.[36] The Commission stated, "[i]t is reasonable to expect that, over the long-run, a regulated firm will grow at the rate of the average firm in the economy, because regulation will generally prevent the firm from being extremely profitable during good periods, but also protects it somewhat during bad periods."[37] The D.C. Court of Appeals affirmed the Commission's decision to use GDP to estimate long-term growth in dividends, finding that "[t]he testimony adduced at the hearing demonstrated that major investment houses used an economy-wide approach to project long-term growth, that such an approach was supported by practical economic considerations, and that existing industry-specific approaches imperfectly reflected investor expectations and made unfounded economic assumptions."[38]

21. When the Commission first required use of a long-term growth estimate, the Commission simply averaged the short-term five-year IBES growth estimate with the long-term GDP growth estimate in determining the overall dividend growth rate.[39] However, in 1998, in Opinion No. 414-A, the Commission changed the weighting scheme in order to give two-thirds weight to short-term forecasts and one-third weight to long-term forecasts. The Commission explained,

> While determining the cost of equity nevertheless requires that a long-term evaluation be taken into account, long-term projections are inherently more difficult to make, and thus less reliable, than short-term projections. Over a longer period, there is a greater likelihood for unanticipated developments to occur affecting the projection. Given the greater reliability of the short-term projection, we believe it is appropriate to give it greater weight. However, continuing to give some effect to the long-term growth projection,

---

[36] Opinion No. 396-B, 79 FERC at 62,382-83, *reh'g denied*, Opinion No. 396-C, 81 FERC ¶ 61,036 (1997).

[37] *Id.*

[38] *Williston Basin Interstate Pipeline Co., v. FERC*, 165 F.3d 54, 64 (D.C. Cir. 1999). Nonetheless, finding the record evidence inadequate to support the Commission's use of certain GDP data, the Court remanded the case for further proceedings on this issue. Subsequently, the Commission has used an average of three GDP growth projections.

[39] Opinion No. 396-B, 79 FERC at 62,383, *reh'g denied*, Opinion No. 396-C, 81 FERC ¶ 61,036 (1997).

will aid in normalizing any distortions that might be reflected in short-term data limited to a narrow segment of the economy.[40]

22. The United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) affirmed this two-thirds/one-third weighting for determining the overall dividend growth estimate.[41] Since Opinion No. 414-A, the Commission has made no changes in its two-step DCF methodology used for natural gas and oil pipelines, except to require that, if a master limited partnership (MLP) is included in the proxy group, its long-term growth rate should be one-half the GDP growth estimate.[42] The Commission explained that MLPs have less growth potential than corporations, because they generally distribute to partners an amount in excess of their reported earnings.[43]

23. After the Commission derives a single cost of equity estimate for each member of a natural gas or oil pipeline proxy group, the zone of reasonableness is defined by the low and high estimates of the market cost of equity for the members of the proxy group.

B. One-Step DCF Methodology

24. While the Commission also uses a constant growth DCF model to determine public utility ROEs, the Commission uses a one-step DCF methodology, which differs in numerous ways from the two-step DCF methodology it uses for natural gas and oil pipelines. First, instead of determining a single cost of equity estimate for each proxy company, the one-step DCF methodology determines separate high and low estimates for each proxy company. This is done as follows.

25. First, the Commission calculates two dividend yields for each proxy company – a low average dividend yield and a high average dividend yield, with both averages based on high and low stock prices for each of the six months in the study period. Next, the Commission makes two estimates of dividend growth. One is based on the same IBES analyst five-year growth forecasts used for the short-term growth projection in the two-step DCF methodology. The other is based on the “br + sv” sustainable growth formula, where “b” represents the percentage of earnings expected to be retained (after the payment of dividends), “r” represents the expected rate of return on book equity, “s”

---

[40] Opinion No. 414-A, 84 FERC at 61,423-24.

[41] *CAPP v. FERC*, 254 F.3d at 297.

[42] *Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at P 106.

[43] *Id.* P 12.

represents the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. The "br" component of this formula projects a utility's growth from the investment of retained earnings, and the "sv" component estimates growth from external capital raised by the sale of additional stock.[44] For each input in the "br + sv" formula, the Commission uses an average of the estimates published in *Value Line* for the current year, the next year, and three- to five-years in the future.[45]

26. The low cost of equity estimate for each proxy company is determined by adding the lower of the two growth projections for that company to the low dividend yield. The high cost of equity estimate for each company is determined by adding the higher of the two growth estimates for that company to the high dividend yield.[46] If the proceeding involves a group of electric utilities, the Commission uses the lowest of the proxy company low estimates to determine the bottom of the range of reasonable returns and the highest of the proxy company high estimates to determine the top of the range and then generally sets the base ROE for the group at the midpoint of the range. If the proceeding involves a single company, the Commission averages the high and low cost of equity estimates of each proxy company, and sets the ROE for the electric utility at the median value of the range of reasonable returns.[47]

27. The most significant difference between the one-step and two-step DCF methodologies is the lack of a long-term growth projection in the one-step DCF methodology. After the Commission held in *Ozark* that the DCF model requires use of a long-term growth projection in natural gas pipeline cases, the issue arose whether the Commission should also modify its electric DCF methodology to include a long-term growth projection. In 1999, in an Initial Decision involving Southern California Edison Company, [48] the Presiding Judge adopted a two-step DCF formula with a long-term growth projection for a public utility, because he found it consistent with the

---

[44] However, in the absence of reliable record evidence on expected common stock issuances, the "sv" component is generally considered to be zero.

[45] *See S. Cal. Edison Co.*, 92 FERC ¶ 61,070, at 61,263 (1999).

[46] *Id.* at 61,264; *see also Appalachian Power Co.*, 83 FERC ¶ 61,335, at 62,350 (1998).

[47] *S. Cal. Edison Co. v. FERC*, 717 F.3d 177, 183-87 (D.C. Cir. 2013).

[48] *S. Cal. Edison Co.*, 86 FERC ¶ 63,014 (1999).

Commission's recent precedent in natural gas pipeline cases.[49] In contrast to the approach taken in natural gas and oil pipeline cases, the Commission had consistently applied a one-step, constant growth DCF model for determining allowed ROEs for public utilities.[50] On September 17, 1999, in response to exceptions taken to the Initial Decision on how best to determine the allowed ROE for Southern California Edison Company, the Commission issued an "Order Establishing Further Proceedings on Issue of Rate of Return on Common Equity."[51]

28. Based on a review of the record developed in the reopened proceeding, the Commission issued Opinion No. 445, which reversed the Initial Decision and found that the time was not ripe to apply the two-step DCF methodology in public utility cases.[52] The Commission stated that, up until that time, it had not expressly addressed the differing approaches taken in determining the allowed ROE in natural gas/oil pipeline and public utility cases. The Commission in Opinion No. 445 then compared the two industries and concluded "that significant differences exist in the electric utility industry and the natural gas pipeline industry which warrant the continued use of different growth rates in the DCF models for each."

29. The Commission explained that the electric industry was just beginning a significant new phase of its restructuring, while the gas pipeline industry had nearly completed its major restructuring when Opinion No. 396-B was issued in 1997.[53] In particular, at the time of its filing, Southern California Edison Company had just begun to

---

[49] *Id.* at 65,143 (citing *Williston Basin Interstate Pipeline Co*., 50 FERC ¶ 61,284 (1990), *vacated on other grounds*, 931 F.2d 948 (D.C. Cir. 1991); Opinion No. 396-B, 79 FERC ¶ 61,309, *reh'g denied*, Opinion No. 396-C, 81 FERC ¶ 61,036; and *Transcon. Gas Pipe Line Corp.*, Opinion No. 414, 80 FERC ¶ 61,157 (1997), *order on reh'g*, Opinion No. 414-A , 84 FERC ¶ 61,084.

[50] *See, e.g., Consumers Energy Co.*, 85 FERC ¶ 61,100 (1998); *Sw. Pub. Serv. Co.*, 83 FERC ¶ 61,138 (1998); *Appalachian Power Co.*, 83 FERC ¶ 61,335; *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC ¶ 61,001 (1996); *S. Cal. Edison Co.*, 56 FERC ¶ 61,003, *order on reh'g*, 56 FERC ¶ 61,117 (1991); *Conn. Light & Power Co.*, Opinion No. 305, 43 FERC ¶ 61,508 (1988).

[51] *S. Cal. Edison Co.*, 88 FERC ¶ 61,254 (1999).

[52] *S. Cal. Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070, at 61,261 (2000).

[53] *Id.*

restructure from a vertically integrated utility.[54] Indeed, with the electric industry in flux and the future so uncertain, it seemed too speculative to assume that investors were reflecting long-term growth estimates in their investment decisions.

30. In addition, the Commission observed that there was a significant difference in the short-term growth rates between Southern California Edison Company and gas pipeline companies versus GDP growth rates. While the short-term growth rates of natural gas pipeline proxy group companies were all significantly higher than the projected growth in GDP, that was not true for public utilities.[55] The Commission attributed this difference to the higher dividend payout ratios of public utilities, which produce lower growth from retained earnings, and the resulting lower dividend growth.[56] With such a wide gap between short-term and long-term natural gas pipeline growth rates, the implication was that the two-step DCF methodology was better suited to the natural gas pipeline industry than to the electric utility industry because the short-term dividend growth rates for public utilities did not deviate significantly from GDP rates.

31. Moreover, the record in the Opinion No. 445 proceeding contained evidence that two large investment firms use the long-term growth of the economy as a whole in their analyses of natural gas pipeline companies, while one of them indicated that it treated electric utilities differently from all of the other industrial companies when estimating growth rates.[57] For all of these reasons, the Commission found that it would be "premature" at that time to incorporate a GDP estimate in the DCF methodology applicable to an electric utility company.[58] Therefore, the Commission calculated the ROE for Southern California Edison Company using the one-step, constant growth DCF methodology and has continued to use this approach in electric utility cases.

---

[54] *Id.*

[55] *S. Cal. Edison Co.*, 92 FERC at 61,261 (citing *Ozark*, 68 FERC at 61,104-05 (growth estimates ranging from 8.81 percent to 15.2 percent and GDP estimates of 5.4 percent)); *Williston Basin Interstate Pipeline Co.*, 72 FERC ¶ 61,074, at 61,387 (growth estimates ranging from 8 to 15 percent and GDP estimates of 5.37 percent and 6.33 percent); Opinion No. 414-A, 84 FERC ¶ 61,084 at Appendix A (growth estimates ranging from 8 percent to 15 percent and a GDP estimate of 5.45 percent).

[56] Opinion No. 445, 92 FERC at 61,262.

[57] *Id.*.

[58] *Id.*

Significantly, though, the Commission added that "[s]hould circumstances in the industry change, in the future, we will reevaluate our methodology, as necessary."[59]

C. <u>Adoption of the Two-Step DCF Methodology for Public Utility Rate Cases</u>

32. This proceeding has caused the Commission to revisit its historical use of DCF analyses to determine the allowed ROE in public utility cases, given the evolution of the electric industry since issuance of Opinion No. 445. Based on this review, the Commission finds that it is now appropriate to change the way DCF analyses are conducted in public utility cases to use the same methodology as the Commission uses in natural gas and oil pipeline cases. In theory, an analytical tool such as the DCF model is equally applicable to all companies, whether they are public utilities, natural gas pipeline companies, or oil pipeline companies.

33. The DCF model is based on the premise that an investment in common stock is worth the present value of the infinite stream of future dividends discounted at a market rate commensurate with the investment's risk. Corporations have indefinite lives and therefore will pay dividends for an indefinite period. For that reason, the Commission stated as long ago as 1983, when it first adopted the constant growth DCF model for gas pipeline cases, that "projections by investment advisory services of growth for relatively short periods of years into the future"[60] cannot be relied on "without further consideration." Thus, as the Commission held in *Ozark*, the constant growth DCF model requires consideration of long-term growth projections.

---

[59] *Id.* In Opinion No. 446, the Commission similarly rejected a proposal to use the two-step DCF methodology for a public utility, for essentially the same reasons as in Opinion No. 445. *Sys. Energy Resources, Inc.*, Opinion No. 446, 92 FERC ¶ 61,119, at 61,443-46 (2000). In addition, the Commission stated that use of the two-step DCF methodology could overcompensate the public utility for its cost of equity. The Commission pointed out that the internal growth rate of public utilities averaged only 2.51 percent during the 1993-1997 period and was projected to be 3.86 percent in 2002, as compared to 20-year GDP growth projections in that case of 5.0 and 5.2 percent (and in contrast to natural gas pipeline growth rates that exceeded GDP). The Commission attributed these low internal growth rates to public utilities' high dividend payout ratios, and stated that combining a public utility's high dividend yield with growth rates reflecting the projected growth in GDP could overestimate the utility's cost of capital.

[60] *Consol. Gas Supply Corp.*, 24 FERC at 61,105.

34. Both growth projections used in the existing one-step DCF methodology rely on growth projections by investment advisory services for relatively short periods of years. The IBES growth projections are for only five years. While the "br + sv" growth formula used in public utility rate cases seeks to estimate a company's sustainable growth, it relies on short-term *Value Line* projections of the various inputs to the formula for the current year, the next year, and a year three- to five-years in the future. For that reason, the Commission has previously held that the "br + sv" formula only produces a projection of short-term growth, similar to the IBES projections.[61] Thus, the one-step DCF methodology does not include a long-term growth projection of the type ordinarily required by the constant growth DCF model.

35. When, in 2000, the Commission nevertheless decided not to adopt the two-step DCF methodology in the Opinion No. 445 proceeding, an important consideration was the fact that Southern California Edison Company and other public utilities were only just beginning the process of restructuring. Given the anticipated changes in the industry at that time, it did not seem to be an appropriate time to reflect an estimate of long-term growth in dividends in the DCF model. In those circumstances, the Commission's view was that investors would be unlikely to place much weight on long-term forecasts because the uncertainties regarding the future were so great.[62] Regulatory change is an inevitable part of any regulated industry. However, the investor uncertainty due to the type of changes anticipated in 2000 has diminished.

36. Therefore, we now believe that the time has come to apply the DCF methodology in public utility cases in a manner more consistent with the way it is applied in natural gas and oil pipeline cases. Most importantly, including a long-term estimate of dividend growth in the constant growth DCF model, as is done in natural gas/oil pipeline cases, will now bring the public utility ROE approach into full alignment with the underlying theory of the DCF model.[63]

---

[61] *Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at P 100 (citing Opinion No. 445, 92 FERC at 61,262-3).

[62] Opinion No. 445, 92 FERC at 61,261-61,262.

[63] Incorporating a long-term growth estimate in the DCF methodology is consistent with the underlying theory of the constant growth DCF model because

> from the standpoint of the DCF model that extends into perpetuity, analysts' horizons are too short, typically five years. It is often unrealistic for such growth to continue in perpetuity. A transition must occur between the first stage of growth forecast by analysts for the first five years and the

(continued…)

37. In addition, the Commission believes that developing a zone of reasonableness pursuant to the two-step DCF methodology with its use of a single cost of equity estimate for each proxy company is less likely to produce the anomalous results that can result from combining high and low dividend yields with high and low short-term projections of dividend growth to produce two estimates for each proxy company. For example, to the extent a high DCF estimate is based on an IBES five-year projection, that result is inconsistent with the theory underlying the constant growth DCF model, which requires an estimate of dividend growth extending into the indefinite future. Moreover, the purpose of the sustainable "br + sv" growth estimate is to act as a check on the reasonableness of IBES forecasts. In practice, however, the two growth rates are used independently to establish high and low estimates of the cost of equity for electric utilities. The end result is often a zone of reasonableness that is defined by two widely divergent growth rates that do not engender much confidence in the reliability of the estimates.

38. The Commission recognizes that the IBES growth projections of electric utilities continue to reflect a different pattern from those of natural gas and oil pipelines. While pipeline IBES growth projections are consistently higher than projections of long-term growth in GDP growth, that is not true of public utilities. For example, the IBES growth projections for the national proxy group we adopt in this case range from 2.0 percent to 8.10 percent, as compared to long-term projected growth in GDP of 4.39 percent.[64] However, we no longer believe the generally lower IBES short-term growth projections of public utilities justify not including a long-term growth projection in the DCF analysis of electric utilities. As the Commission stated in Opinion No. 414-A, giving "some effect to the long-term growth projection will aid in normalizing any distortions that might be reflected in short-term data limited to a narrow segment of the economy."[65] This is true, regardless of whether the short-term growth projection is greater or less than the growth in the economy as a whole. Over the long-run, a regulated firm may reasonably be expected to grow at the rate of the average firm in the economy; growth either

---

> company's long-term sustainable growth rate. . . . It is useful to remember that eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy.

Roger A. Morin, New Regulatory Finance 308 (Public Utilities Reports, Inc. 2006).

[64] Moreover, four public utilities, which we are excluding from the proxy group in this case, have negative IBES growth projections.

[65] Opinion No. 414-A, 84 FERC at 61,423.

significantly above or below the growth of the economy as a whole is unlikely to continue indefinitely. Using the same long-term growth projection for all public utilities is consistent with this expectation. It also produces a narrower zone of reasonableness, consistent with the fact different firms in a regulated industry would not ordinarily be expected to have widely varying levels of profitability.

39. Therefore, in this proceeding, and in future public utility cases, the Commission will adopt the same two-step DCF methodology used in natural gas and oil pipeline cases.[66] In other words, there will be a single, six-month average dividend yield for each company in the proxy group. More importantly, the estimate of the dividend growth rate for each company in the proxy group will now include a short-term projection of dividend growth (with a two-thirds weight) and a long-term projection of dividend growth (with a one-third weight). The short-term growth estimate will be based on the five-year projections reported by IBES (or a comparable source). Given the absence of an electric industry-specific long-term growth projection that reasonably reflects investor expectations, the long-term growth estimate will be based on an average of the GDP growth rates that have been relied on in gas and oil pipeline cases.[67]

40. We also find that it is reasonable to expect that public utilities, which transmit electricity to supply energy to the national economy, will sustain growth consistent with the growth of the economy as whole.[68] This conclusion is buttressed by the fact that the current three to five year projected internal growth rate of electric utilities approximates the projected growth in GDP. The median internal growth rate of the 41 electric utilities in the proxy group before application of the low-end outlier test is 4.32 percent, and the midpoint internal growth rate for those utilities is 4.55 percent.[69] These growth rates are

---

[66] As noted *supra* at n.25, the Commission will apply the two-step methodology to all pending ROE-related complaint cases, including those that have been set for hearing.

[67] In Opinion No. 396-B, the Commission based the GDP growth rate on forecasts made by the Energy Information Administration (EIA), DRI/McGraw Hill, and Wharton Economic Forecasting Associates (Wharton). Opinion No. 396-B, 79 FERC at 62,384-62,385. Over time, however, the sources of GDP data have changed. Currently, the Commission uses GDP data from EIA, Social Security Administration, and IHS Global Insight (which was formed by the merger of DRI/McGraw Hill and Wharton). *See Portland Natural Gas Transmission Sys.*, 137 FERC ¶ 63,018, at PP 121-128 (2011), *aff'd in relevant part*, Opinion No. 524, 142 FERC ¶ 61,197 at PP 317-320.

[68] *See supra* n.63.

[69] *See* Ex. NET-703.

very close to the 4.39 percent projected long-term growth in GDP. While the Commission, in Opinion No. 446, declined to apply the two-step DCF methodology to public utilities based in part of the fact their internal growth rates were less than GDP, that disparity no longer exists.[70] In Opinion No. 446, the Commission explained that the two-step DCF methodology could overcompensate a public utility for its cost of equity because GDP was approximately double the internal grow rates of the companies analyzed in that proceeding.[71] Because public utilities' internal growth rates now approximate GDP, incorporating GDP into public utilities' cost of equity estimates will not overcompensate those utilities. For this reason, the Commission no longer sees a reason to use a long-term growth projection for public utilities that is less than the projected long-term growth of GDP.

41. For the reasons discussed above, the Commission concludes that using, in public utility cases, the same formulation of the DCF model used for natural gas/oil proceedings is consistent with the underlying theory of the DCF model and is preferable to the one-step DCF methodology. However, we also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses in determining where to set a public utility's ROE within the range of reasonable returns established by the two-step constant growth DCF methodology.

D. Implementation of the Two-Step DCF Methodology in This Case

42. While the NETOs raised concerns at the hearing in this case as to whether the Commission's existing electric DCF analysis accurately reflects investor expectations, no participant in the hearing proposed to use the two-step DCF methodology. Thus, the participants have not had an opportunity to present evidence on issues raised by implementation of the two-step constant growth method that do not arise under our existing electric DCF methodology. However, there is considerable overlap in the issues that arise when conducting either type of DCF analysis, and all of the financial evidence necessary to apply the two-step DCF methodology in this case is in the evidentiary record developed at the hearing, with the exception of necessary GDP growth projections.

[70] *See* Opinion No. 446, 92 FERC at 61,443-61,446.

[71] *Id.*, *supra* n. 59.

43. For the reasons provided above, we find that the NETOs' ROE to be established in this case should be determined using the two-step DCF methodology. Based on the extensive record developed at the hearing in this case, together with taking official notice of the appropriate long-term GDP growth projections, we will make tentative findings in this order, based on the record thus far in this proceeding, concerning whether the NETOs' existing base ROE is unjust and unreasonable and what the just and reasonable ROE for the NETOs is under the two-step DCF methodology. However, as discussed below, we will reopen the record for the limited purpose of allowing the participants to this proceeding an opportunity to present written evidence concerning issues unique to the application of the two-step DCF methodology to the facts of this proceeding. Specifically, this will give the participants an opportunity to present evidence concerning the appropriate long-term growth projection to be used for public utilities under the two-step DCF methodology. As discussed in more detail below, we find that the participants have had ample opportunity to litigate all other issues in this proceeding and, therefore, will not entertain those issues in the paper hearing. After reviewing the pleadings submitted during the paper hearing, we will make a final determination of the NETOs' just and reasonable base ROE.

IV. Burden of Proof

A. Initial Decision

44. The Presiding Judge found that the Complainants and Trial Staff hold the burden to establish that the current ROE is unjust and unreasonable, and that they have met that burden in this case.[72] The Presiding Judge rejected the NETOs' argument that the existing base ROE should be retained because it falls within the zone of reasonableness of the DCF analyses, explaining that "a bright line litmus test of this sort" is contrary to Commission precedent and illogical when applied to the facts of this case.[73] The Presiding Judge found that the Commission has previously rejected this argument in *Bangor Hydro*.[74] The Presiding Judge further explained that all of the evidence in this case supports the finding that the existing 11.14 percent base ROE is no longer just and reasonable.

---

[72] Initial Decision, 144 FERC ¶ 63,012 at P 546.

[73] *Id.* P 547.

[74] *Id.* P 547 (citing *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,038 (2008) (*Bangor Hydro*)).

B. Briefs on Exceptions

45. The NETOs argue both that the Complainants have the burden to show that the existing base ROE is unjust and unreasonable, and that the Commission does not have statutory authority to change the existing base ROE unless the evidence shows that it is entirely outside the zone of reasonableness. The NETOs assert that the Complainants have not met this burden. The NETOs further contend that the Initial Decision did not acknowledge or examine the Commission and court precedent on this issue—specifically, *City of Winnfield* and *Texas Eastern*.[75] The NETOs argue that the Initial Decision also overlooks years of case law that links the zone of reasonableness to the determination of whether a rate is just and reasonable,[76] and relies on only one case *Bangor Hydro*, which is both distinguishable and contrary to D.C. Circuit precedent.[77] The NETOs further contend that the principle that rates have to be outside the zone of reasonableness to be unjust and unreasonable is also recognized under the Interstate Commerce Act.[78]

C. Briefs Opposing Exceptions

46. According to Trial Staff, all parties agree that the Initial Decision correctly determined that the parties challenging the existing base ROE bear the burden of showing that it is unjust and unreasonable. Trial Staff further asserts that the Initial Decision properly determined that the burden has been met in this case. Trial Staff, the Complainants, and EMCOS state that the Commission is not required to accept an ROE merely because it falls within the zone of reasonableness, and the Commission already rejected the NETOs' argument to the contrary in *Bangor Hydro*. EMCOS state that the Initial Decision correctly follows *Bangor Hydro* in finding that the determination of a just

---

[75] NETOs Brief on Exceptions at 10-11 (citing *City of Winnfield v. FERC*, 744 F.2d 871 (D.C. Cir. 1984) (*City of Winnfield*); *Texas Eastern Transmission Corp.*, 32 FERC ¶ 61,056 at 61,150, n.6 (1985) (*Texas Eastern*)).

[76] NETOs Brief on Exceptions at 13-15 (citing *Me. Pub. Utilities Comm'n v. FERC*, 520 F.3d 464, 470-471 (D.C. Cir. 2008), *rev'd in part on other grounds sub nom. NRG Power Mktg., LLC v. Me. Pub. Utilities Comm'n*, 558 U.S. 165 (2010); *Calpine Corp. v. Cal. Indep. Sys. Op. Corp.*, 128 FERC ¶ 61,271, at P 41 (2009); *Cal. Indep. Sys. Op. Corp.*, 140 FERC ¶ 61,168, at P 17 (2012); *Montana-Dakota Utils. Co. v. Nw. Pub. Serv. Co.*, 341 U.S. 246, 251 (1951) (*Montana-Dakota*)).

[77] NETOs Brief on Exceptions at 19 (citing *Bangor Hydro*, 122 FERC ¶ 61,038).

[78] *Id.* at n.16 (citing *Lakehead Pipe Line Co., Ltd. P'ship,* 65 FERC ¶ 63,021, at 65,137 (1993)).

and reasonable ROE does not turn on whether the ROE falls within the zone of reasonableness, but instead requires a balancing of interests that reflects the unique circumstances of each case.[79]

47. The Complainants and EMCOS contend that the NETOs' argument contradicts controlling judicial precedent,[80] and is unsupported by *City of Winnfield* and *Texas Eastern*.[81] Similarly, Trial Staff asserts that the Presiding Judge properly considered *City of Winnfield* and *Texas Eastern*, as well as other relevant case law, in rejecting the NETOs' argument.[82] Trial Staff contends that *City of Winnfield* involved an FPA section 205 proceeding in which the court's discussion of FPA section 206 is dicta, and asserts that *Texas Eastern* is distinguishable because it dealt with issues of cost allocation and rate design, not base ROE. The Complainants argue that Commission precedent involving cases in which both the zone of reasonableness and ROE were at issue clearly indicate that the zone of reasonableness is not a zone of immunity.[83]

48. The Complainants argue that the NETOs' zone of immunity argument is contrary to the Regulatory Fairness Act.[84] The Complainants also argue that Order No. 679 and Commission precedent on incentive ROE adders do not render any ROE below the top of the zone of reasonableness ipso facto reasonable; rather, the Complainants assert that those cases hold that the Commission is authorized to place the total ROE below the top

---

[79] EMCOS Brief Opposing Exceptions at 10-11.

[80] Complainants Brief Opposing Exceptions at 11-13 (citing *FPC v. Natural Gas Pipeline Co.*, 315 U.S. 575 (1942); *FPC v. Conway Corp.*, 426 U.S. 271, 278-279 (1976); *Montana-Dakota*, 341 U.S. 246); EMCOS Brief Opposing Exceptions at 7-8 (citing *FPC v. Conway Corp.*, 426 U.S. at 278-79).

[81] Complainants Brief Opposing Exceptions at 14-18.

[82] Trial Staff Brief Opposing Exceptions at 11 (citing Initial Decision, 144 FERC ¶ 63,012 at n.45).

[83] Complainants Brief Opposing Exceptions at 21 (citing *Golden Spread Elec. Coop. Inc. v. Sw. Pub. Serv. Co.*, Opinion No. 501, 123 FERC ¶ 61,047 (2008), *order on reh'g*, 144 FERC ¶ 61,132 (2013); *Orange & Rockland Utils., Inc.*, Opinion No. 314, 44 FERC ¶ 61,253, at 61,953-55, *modified*, Opinion No. 314-A, 45 FERC ¶ 61,252 (1988), *reh'g denied*, 46 FERC ¶ 61,036 (1989); *Yankee Atomic Elec. Co.*, 40 FERC ¶ 61,372, at 62,212 (1987), *modified*, 43 FERC ¶ 61,232 (1988)).

[84] Complainants Brief Opposing Exceptions at 21-22.

of the zone after applying the adders to a base ROE that represents the Commission's best estimate of a cost-based equity return.[85] Lastly, the Complainants assert that the NETOs' reliance on the Interstate Commerce Act's "Maximum Reasonable Rate" standard is misplaced because it ignores significant differences between the ICA and the FPA, and because the Interstate Commerce Act does not repeal the FPA's just and reasonable standard.[86]

D. Commission Determination

49. We affirm the Presiding Judge's determination on the burden of proof.

50. Under FPA section 206, the burden of proof to show that a rate is unjust and unreasonable "shall be upon the Commission or the complainant."[87] As to what that burden entails in the context of an ROE proceeding, the Supreme Court has held that a just and reasonable ROE should be "commensurate with returns on investments in other enterprises having corresponding risks . . . [and] sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[88] An ROE above that level would exploit consumers and is, therefore, unjust and unreasonable.[89] To estimate the rate of return necessary to attract equity investors, the Commission uses the DCF model, which assumes that a stock's price is equal to the

---

[85] *Id.* at 24-25 (citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 93; *Promoting Transmission Investment Through Pricing Reform*, 141 FERC ¶ 61,129, at P 11 (2012); *Atl. Grid Operations A LLC, et al.*, 135 FERC ¶ 61,144, at PP 88, 94 (2011)).

[86] Complainants Brief Opposing Exceptions at 26-27.

[87] 16 U.S.C. § 824e(b) (2012).

[88] *Hope*, 320 U.S. at 603; *see also Bluefield*, 262 U.S. at 693 ("The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.").

[89] *Jersey Cent. Power & Light Co. v. FERC*, 810 F.2d 1168, 1180 (D.C. Cir. 1987) (*en banc*) ("In addition to prohibiting rates so low as to be confiscatory, the holding of [*Hope*] makes clear that exploitative rates are illegal as well."); *see also Washington Gas Light Co. v. Baker*, 188 F.2d 11, 15 (D.C. Cir. 1950), *cert. denied*, 340 U.S. 952 (1951).

present value of the infinite stream of expected dividends discounted at a market rate commensurate with the stock's risk.[90]

51. We reject the NETOs' argument that the Commission does not have the authority under FPA section 206 to change the existing base ROE unless the evidence shows that it is entirely outside the zone of reasonableness. As the Presiding Judge correctly noted, the Commission previously rejected this argument in *Bangor Hydro*.[91] We do so here for the same reasons. As the Commission explained in that case, the premise of the NETOs' contention is that every ROE within the "zone of reasonableness" is necessarily "just and reasonable." However, this premise is without substantive merit, because it fails to recognize that the determination of a zone of reasonableness is simply the first step in the determination of a just and reasonable ROE for a utility or group of utilities.

> When the Commission identifies a "zone of reasonableness" in a particular case, it identifies a range that reflects the "substantial spread between what is unreasonable because it is too low and what is unreasonable because it is too high." However, not every rate within this "substantial spread" would necessarily be just and reasonable if charged. Certain rates, though within the zone, may not be just and reasonable given the circumstances of the case.[92]

52. The decision of the United States Court of Appeals for the District of Columbia Circuit in *S. Cal. Edison Co. v. FERC*,[93] supports this conclusion. In that case, the utility filed to modify its rates under FPA section 205. The court stated that section 205 required the Commission to approve the utility's rate proposal "as long as the new rates are just and reasonable."[94] Nevertheless, the court also held that the Commission had

---

[90] *See, e.g., S. Cal. Edison Co. v. FERC*, 717 F.3d at 179.

[91] *See Bangor Hydro*, 122 FERC ¶ 61,038 at PP 10-15.

[92] *Id.* P 11 (quoting *Montana-Dakota*, 341 U.S. at 251).

[93] *S. Cal. Edison Co. v. FERC*, 717 F.3d at 181-82 (finding that the Commission had authority to set a utility's ROE at the median of the zone of reasonableness even though the utility proposed using the midpoint, which was also within the zone of reasonableness); *accord Montana-Dakota*, 341 U.S. at 251 (explaining that while statutory reasonableness is an abstract concept represented by an area rather than a pinpoint the Commission must translate that concept into a concrete rate, and it is the rate—not the abstract concept—that governs the rights of the buyer and seller).

[94] *S. Cal. Edison Co. v. FERC*, 717 F.3d at 181.

authority to require the utility's ROE to be set at the median of the zone of reasonableness, even though the midpoint ROE proposed by the utility was also within the zone of reasonableness. In short, the court recognized that the Commission need not treat every ROE within the zone of reasonableness as an equally just and reasonable ROE. If the Commission were required to find any and every ROE within the zone of reasonableness to be equally just and reasonable, the Commission would be required to accept any ROE proposed by a utility in a section 205 rate case, even an ROE at the very top of the zone of reasonableness, as long as that ROE did not exceed the top of the range of reasonableness. However, the FPA has never been understood to require such a result.

53. FPA section 206 contains the same "just and reasonable" standard as FPA section 205. Yet the NETOs effectively contend that we must apply a different just and reasonable standard in section 206 cases than in section 205 cases.[95] Despite the fact FPA section 205 does not require that every ROE within the zone of reasonableness be considered equally just and reasonable for purposes of a utility rate filing under FPA section 205, the NETOs would require us to treat every existing ROE within the zone of reasonableness as equally just and reasonable in a section 206 case. Nothing in the FPA, however, supports such a different understanding of the phrase "just and reasonable" as between those two sections of the FPA when establishing a utility's ROE.

54. We further find to be misplaced the NETOs' reliance on *City of Winnfield*, for the proposition that in a section 206 proceeding a utility's existing rates must "be found to be entirely outside the zone of reasonableness before the agency can dictate their level or form." *City of Winnfield* involved a utility's section 205 proposal to design its rates based on incremental fuel costs rather than average system costs; the case did not involve the ROE component of a utility's cost of service. Thus, the court was not using the phrase "zone of reasonableness" as it is commonly used in proceedings involving a utility's ROE.[96]

---

[95] Given that the FPA was intended to be a consumer-protection statute, *see, e.g.*, *Pub. Sys. v. FERC*, 606 F.2d 973, 979 n.27 (D.C. Cir. 1979), it is hard to find persuasive an argument that would allow, under FPA section 205, a utility to propose an increase in its ROE to anywhere in the zone, but would effectively bar, under FPA section 206, a customer from seeking to decrease the ROE being challenged merely because the ROE falls somewhere within the zone.

[96] The Commission's *Texas Eastern* order, also relied on by the NETOs, is distinguishable for the same reason, because it also involved cost allocation and rate design issues, rather than the determination of an entity's ROE.

55. For these reasons, we therefore conclude that the zone of reasonableness produced by a DCF analysis does not create a zone of immunity for a utility's ROE.

V. Appropriate Time Period for the Base ROE in this Proceeding

A. Initial Decision

56. The Presiding Judge found that a separate, higher ROE is appropriate for the "locked in/refund period" from October 2011 through December 2012,[97] and therefore established two separate ROEs: one for the refund period and one to apply prospectively.[98] The Presiding Judge found the just and reasonable base ROE for the refund period to be 10.6 percent, based on the NETOs' DCF data from May 2012 through October 2012, and the just and reasonable base ROE for the prospective period to be 9.7 percent, based on the NETOs' DCF data from October 2012 through March 2013.[99] The Presiding Judge stated that the DCF analysis and data for the period October 2011 through December 2012 "clearly support a higher ROE" than the data for the prospective period. In establishing two base ROEs, using two different data sets and zones of reasonableness, the Presiding Judge reasoned that the "refund period should be representative of what the true ROE was when calculating refunds, otherwise it would allow for a windfall and a return of excessive refunds, based upon supporting data which did not exist at the time."[100]

B. Briefs on Exceptions

57. The Complainants, EMCOS, and Trial Staff argue that the Initial Decision erred in adopting two base ROEs in this proceeding.[101] The Complainants, EMCOS, and Trial

---

[97] The refund period is the 15-month period commencing on the refund effective date established in an FPA section 206 proceeding. In this case, the refund period is October 1, 2011 (i.e., the refund effective date) through December 31, 2012.

[98] Initial Decision, 144 FERC ¶ 63,012 at P 585. The Presiding Judge adopted the NETOs' values for both time periods, establishing base ROEs of 10.6 percent for the refund period and 9.7 percent for the prospective period. *Id.*

[99] *See id.* P 585 (citing NETOs June 6, 2013 Initial Brief at 19).

[100] Initial Decision, 144 FERC ¶ 63,012 at P 585.

[101] Complainants Brief on Exceptions at 19; EMCOS Brief on Exceptions at 19; Trial Staff Brief on Exceptions at 77.

Staff contend that the Commission uses the term "locked-in period" to describe two specific situations, neither of which are present in this case: (1) the rate being litigated has been superseded or is no longer in effect,[102] or (2) significant time has elapsed between the closing of the record and when the Commission issues its order.

58. The Complainants argue that FPA section 206(b) makes clear that the just and reasonable rate to be used in calculating refunds and the just and reasonable rate to be observed prospectively are the same,[103] and this is confirmed by the legislative history of the Regulatory Fairness Act through which that refund provision was added to the FPA.[104] The Complainants also argue that the Initial Decision's establishment of two base ROEs is contrary to Commission precedent clearly indicating that the Commission establishes a single zone of reasonableness and a single ROE.[105] The Complainants

---

[102] Complainants Brief on Exceptions at 21 (citing Opinion No. 501, 123 FERC ¶ 61,047 at P 65, *order on reh'g*, 144 FERC ¶ 61,132); EMCOS Brief on Exceptions at 19-20 (citing Opinion No. 501, 123 FERC ¶ 61,047 at P 65; *Blue Ridge Power Agency v. Appalachian Power Co.*, Opinion No. 363, 55 FERC ¶ 61,509, at 62,785 (1991)); Trial Staff Brief on Exceptions at 80 (citing *S. Cal. Edison Co.*, 139 FERC ¶ 61,042, a P 21 (2012); *S. Cal. Edison Co.*, 137 FERC ¶ 61,016, at P 33 (2011); Opinion No. 501, 123 FERC ¶ 61,047 at P 56; Opinion No. 363, 55 FERC at 62,785).

[103] Complainants Brief on Exceptions at 22-23 (citing *San Diego Gas & Elec. Co. v. Sellers of Ancillary Services Into Markets Operated by the Cal. Indep. Sys. Op. Corp. and Cal. Power Exchange Corp.*, 127 FERC ¶ 61,191, at PP 19-20 (2009)).

[104] Complainants Brief on Exceptions at 23 (citing 134 Cong. Rec. 25,129 (1988) (colloquy of Representatives Gejdenson (D-CT) and Sharp (R-IN)).

[105] Complainants Brief on Exceptions at 27-34 (citing Opinion No. 510, 134 FERC ¶ 61,129, *order on reh'g*, 142 FERC ¶ 61,198; Opinion No. 363, 55 FERC ¶ 61,509, *reh'g granted*, Opinion No. 363-A, 57 FERC ¶ 61,100 (1991), *reh'g granted*, Opinion No. 363-B, 58 FERC ¶ 61,193 (1992); *Golden Spread Elec. Coop., Inc. v. Southwestern Pub. Serv. Co.*, 115 FERC ¶ 63,043, at P 104 (2006), *on exceptions*, Opinion No. 501, 123 FERC ¶ 61,047, at PP 62, 65, n.133; Opinion No. 445, 92 FERC ¶ 61,070; Opinion No. 489, 117 FERC ¶ 61,129; *S. Cal. Edison Co.*, 131 FERC ¶ 61,020, at PP 21, 101, *reh'g denied*, 137 FERC ¶ 61,016, *rev. in part granted in part sub nom. S. Cal. Edison Co. v. FERC*, 717 F.3d 177; *Sw. Pub. Serv. Co.*, 53 FERC ¶ 61,084, at 61,240 (1990), *reh'g denied*, 53 FERC ¶ 61,406 (1990)); Trial Staff Brief on Exceptions at 82 (citing *Golden Spread Elec. Coop., Inc., et al. v. Southwestern Pub. Serv. Co.*, 109 FERC ¶ 61,321, at P 16 (2004); Opinion No. 445, 92 FERC ¶ 61,070).

further assert that the Initial Decision's dual ROE approach would be poor policy because it would add "pointless complexity and gaming to ROE litigation."[106]

59. EMCOS contend that setting a single ROE, even when the DCF data for a refund period differs from the DCF data used to set the ROE, is consistent with the "constantly changing nature of DCF analyses and ROEs."[107] EMCOS further argue that the Initial Decision's rationale for setting two ROEs, i.e., that doing so is necessary to avoid a windfall to ratepayers, ignores the fact that ratepayers only benefit from 15 months of refund protection. Thus, EMCOS assert that the Initial Decision fails to adequately balance the interests of investors and ratepayers.[108]

60. Trial Staff states that a policy of setting two base ROE's in one proceeding would lead to illogical results because a simple shift in the procedural schedule would result in both the initial ROE analysis and the updated ROE analysis being based on data from the refund period. Trial Staff asserts that Commission policy on what constitutes a "locked-in period" should not be based on "a mere happenstance shift of a few months in the procedural schedule of a particular case."[109] Further, Trial Staff argues that *Kern River Transmission Co.*, 126 FERC ¶ 61,034 (2009) (*Kern River*), the one case the NETOs cite in favor of two base ROEs, is distinguishable from this case because *Kern River* involved a full rate case in which the ROE data was from 2008 but the data for the utility's other cost of service elements were based on data from a 2004 test period.[110] Trial Staff asserts that the issue in *Kern River* was the synchronization of data over a five-year period, whereas the instant case involves a four-month difference between the end of the refund period and the end of the six-month data period used for determining the base ROE, and involves no synchronization issues.

---

[106] Complainants Brief on Exceptions at 34.

[107] EMCOS Brief on Exceptions at 21 (citing *Bluefield*, 262 U.S. at 693; *Consumer Advocate Div. of the Pub. Serv. Comm'n of West Virginia*, 68 FERC ¶ 61,207, at 61,998 (1994)).

[108] EMCOS Brief on Exceptions at 21-22.

[109] Trial Staff Brief on Exceptions at 79.

[110] Trial Staff Brief on Exceptions at 81 (citing *Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034 (2009) (*Kern River*)).

C. Brief Opposing Exceptions

61. The NETOs argue that the Presiding Judge properly recognized that the base ROE for the refund period should reflect the best record evidence of the cost of equity during that period and the base ROE for the prospective period should be based on the most recent data in the record, and therefore it was appropriate for the Presiding Judge to establish two base ROEs. The NETOs contend that the refund period is a "locked-in period" because the Commission establishes that a rate is "locked-in" when "the rate being litigated has been superseded *or is otherwise no longer in effect*."[111] The NETOs argue that after December 31, 2012 the base ROE for the refund period will no longer be in effect because the base ROE will revert to 11.14 percent[112] until the Commission issues its order on the Initial Decision, at which time the Commission will adjust the base ROE that will apply from the date of the order on the Initial Decision to reflect changes in the 10-year U.S. Treasury bonds.

62. The NETOs also argue that the base ROE for the refund period should reflect the best record evidence of the cost of equity during that period, regardless of whether it is a "locked-in period," and to find otherwise would be contrary to ratemaking principles and precedent.[113] The NETOs argue that the Commission's standard practice in electric ROE cases is to use DCF data from during or before the refund period to establish an ROE for the refund period, and none of the cases cited by the Complainants, EMCOS, or Trial Staff support the proposition that the refund period ROE should be based on DCF data from after the close of the refund period.[114]

63. The NETOs contend that FPA section 206(b) does not preclude establishing separate ROEs for the refund and prospective periods, and that this is demonstrated by the Commission's policy of updating ROEs based on changes in the Treasury bond yields, which regularly produces separate rates for the refund period and the prospective period. Further, the NETOs assert that the legislative history of the Regulatory Fairness

[111] NETOs Brief Opposing Exceptions at 71 (quoting Opinion No. 501, 123 FERC ¶ 61,047 at P 65) (internal quotations omitted) (emphasis added by NETOs).

[112] However, the NETOs explain that the rate will instead revert to the level determined in Docket No. EL13-33-000 if the pending complaint in that proceeding is not dismissed. NETOs Brief Opposing Exceptions at n.108.

[113] NETOs Brief Opposing Exceptions at 74-76 (citing *Kern River*, 126 FERC ¶ 61,034 at P 57).

[114] NETOs Brief Opposing Exceptions at 77-79.

Act did not change the Commission's regulatory process or rate setting standards, and therefore supports the Commission's standard practice of establishing the ROE based on data from before or during the refund period.[115]

D. Commission Determination

64. We find that it is inappropriate to establish two base ROEs in this proceeding. The Commission's long-standing practice is to establish one base ROE in a proceeding, using one zone of reasonableness.[116] The Commission has only established different ROEs for different time periods in a proceeding based on post-hearing adjustments to reflect post-hearing changes in U.S. Treasury bond yields, but those adjustments must remain within the single zone of reasonableness established in the proceeding. Notably, the Presiding Judge and the NETOs have cited no precedent in which the Commission established two base ROEs, based on two zones of reasonableness, in one proceeding. Our general policy has also been to base the zone of reasonableness on the most recent financial data in the record.[117] Here, the most recent data in the record are the data for a 6-month study period from October 2012 through March 2013.[118] This data is reasonably representative of the refund period, as it includes the last three months of that period.

---

[115] NETOs Brief Opposing Exceptions at 80-81.

[116] *See, e.g.,* Opinion No. 510, 134 FERC ¶ 61,129, *order on reh'g*, 142 FERC ¶ 61,198; *Sw. Pub. Serv. Co.*, 53 FERC at 61,240, *reh'g denied*, 53 FERC ¶ 61,406.

[117] *See, e.g.,* Opinion No. 489, 117 FERC ¶ 61,129 at P 28; *Sw. Pub. Serv. Co.*, 53 FERC at 61,240, *reh'g denied*, 53 FERC ¶ 61,406. In *S. Cal. Edison Co*., 131 FERC ¶ 61,020 at P 21 (2010), the Commission did not permit use of updated financial data not available at the time of the utility's filing, and instead relied solely on the U.S. Treasury bond adjustment to update the utility's ROE. However, as discussed *infra*, section VII, we are changing our practice to no longer apply the U.S. Treasury bond adjustment, and instead will determine ROE based on the most recent financial data in the record, including post-test period data.

[118] We acknowledge that Trial Staff submitted DCF data for the 6-month period ending April 2013; however, Trial Staff only provided data for the companies in their own regional proxy group. Thus, the data for the period October 2012 through March 2013 are the most recent DCF data in the record for all companies in the national proxy group.

65. The NETOs nevertheless argue that it is appropriate to establish two base ROEs in this proceeding based on two different zones of reasonableness because the refund period is a locked-in period. We disagree. The NETOs assert that the rate being litigated "is no longer in effect," positing that their base ROE will revert to 11.14 percent at the end of the refund period or that the Commission may adjust the base ROE upon issuance of the instant order to reflect changes in U.S. Treasury bond yields. These arguments are not persuasive.

66. Section 206(b) of the FPA provides that

> [a]t the conclusion of any proceeding under this section, the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate . . . which the Commission orders to be thereafter observed and in force.[119]

That the NETOs' need not pay refunds between the end of the fifteen-month refund period and the conclusion of the proceeding is purely a matter of refund liability in the context of a section 206 proceeding, it does not require separate ROEs. In other words, that refunds may only be ordered for fifteen months does not mean that two ROEs are required.

67. The Commission's decision at the end of an FPA section 205 proceeding to update a base ROE to reflect changes in capital market conditions following that proceeding similarly does not dictate that the Commission must set a separate, entirely new ROE to be effective prospectively. When the Commission applies its Treasury bond adjustment to an open-ended rate established in an FPA section 205 proceeding, it applies that adjustment "for the entire period the rates are in effect—both up to the date of the Commission's decision and subsequently."[120] The same approach – adopting a single ROE – is equally appropriate here. Further, we agree with Trial Staff that it would be poor policy to establish two base ROEs in one proceeding based, e.g., solely on a happenstance shift in a proceeding's procedural schedule.

---

[119] 16 U.S.C. § 824e(b) (2012).

[120] *Pac. Gas & Elec. Co.*, 53 FERC ¶ 61,146, at 61,538 (1990). Further, because we are changing our practice to no longer apply the U.S. Treasury bond adjustment, this aspect of the NETOs' argument is moot.

68. The NETOs rely on *Kern River*[121] to argue that Commission policy requires that, where other aspects of a utility's rates are established based on data for a certain time period, those rates should reflect the utility's capital costs during that same period. Therefore, the NETOs argue, their capital costs for the October 2011 to December 2012 refund period must be based on financial data from that period, because the rates they charged during that period reflected their debt and other costs from 2011 to 2012. *Kern River* does not support establishing separate zones of reasonableness for the refund and prospective periods based on the use of financial data from two separate periods. In fact, in *Kern River,* the Commission established a single zone of reasonableness and ROE applicable to both the refund period and prospective period in that NGA section 4 general cost-of-service rate case. In that case, the Commission had to choose between two proxy groups in the record – one based on data from 2004 and one based on data from 2008 – for purposes of determining the pipeline's ROE for all periods. The Commission found that because all other elements of Kern River's rates in that proceeding were being established based on data from a 2004 test year, Kern River's rates should reflect its capital costs from that same time period. Accordingly, the Commission deemed it appropriate to use the data from 2004, rather than data from four years later in 2008, to determine Kern River's cost of equity for both the refund period and going forward. The Commission explained that it would be "internally inconsistent to use debt and equity costs from different periods."[122]

69. Unlike *Kern River*, this proceeding is not a general rate case establishing multiple cost-of-service elements or a utility's weighted cost of capital; rather, it involves only the NETOs' base ROE. Moreover, we are determining the NETOs' cost of capital using data for the six months ending March 2013, which includes the last three months of the refund period; we are not using data from four years after the refund period as some parties sought to do in *Kern River*. As a result, this case does not raise the same types of concerns regarding internal consistency among cost-of-service elements that the Commission faced in *Kern River*. In sum, *Kern River* does not require or support establishing separate ROEs for the refund and prospective periods in this case.

VI. Application of the Two-Step DCF Methodology in This Case

A. General DCF Methodology Issues

70. As discussed below, we affirm the Presiding Judge's finding that the calculation of dividend yields by the Complainants' witness was incorrect and contrary to Commission

---

[121] *See Kern River*, 126 FERC ¶ 61,034.

[122] *Id.* P 57.

policy, and we describe below the correct method of calculating the average dividend yield to be used in the two-step DCF methodology. We also affirm the Presiding Judge's findings concerning the appropriate sources of dividend growth data to be used in a DCF analysis.

1. Calculation of Dividend Yields

i. Initial Decision

71. The Presiding Judge concluded that the NETOs' witness correctly calculated the average high and low dividend yield for each member of the proxy group for the six-month period,[123] and then correctly increased these yields by one-half of the high and low growth rates to convert them to adjusted dividend yields.[124] The Presiding Judge explained that the dividend yields the NETOs' witness calculated in his April 26, 2013 testimony represent the latest monthly dividend yields available at the time he prepared his testimony, and should be used for the ROE analysis.[125]

72. The Presiding Judge stated that the NETOs' witness and Trial Staff's witness calculated their dividend yields in accordance with Commission policy,[126] where each company's high and low dividend yields are calculated for each month of the six-month dividend yield period. The Presiding Judge explained that the high and low dividend yields for a given month are equal to the current annualized dividend divided by the lowest stock price on any day in the month and the current annualized dividend divided by the highest stock price on any day in the month, respectively. The Presiding Judge further explained that the respective high and low dividend yields for the six-month dividend yield period is then equal to the average of the six monthly high or low dividend yields.[127] The Presiding Judge found that the Complainants' witness did not use the

---

[123] Initial Decision, 144 FERC ¶ 63,012 at P 559 (citing Ex. NET-300 at 30).

[124] Initial Decision, 144 FERC ¶ 63,012 at P 559 (citing *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176, at P 119 (2008)).

[125] Initial Decision, 144 FERC ¶ 63,012 at P 560.

[126] *Id.* P 561 (citing *Appalachian Power Co.*, 83 FERC at 62,350).

[127] Initial Decision, 144 FERC ¶ 63,012 at P 561 (citing Ex. S-1 at 40-41; Ex. NET-300 at 30).

Commission's long-standing methodology for calculating the dividend yield,[128] and as a result, those dividend yields and the associated DCF results are fatally defective.

ii. Brief on Exceptions

73. Complainants contend that the difference in how the four witnesses calculated the dividend yields involved the sequence in which daily stock prices were identified and sorted to identify the six past months' high and low averaged share prices. The Complainants state that their witness relied on the monthly dividend yields reported by *AUS Utility Reports*, which calculates those yields based on the daily share price at the middle of each month. The Complainants' witness then used the highest of the dividend yields reported by *AUS Utility Reports* for the six relevant months as the high dividend yield, and the lowest of the six dividend yields as the low dividend yield. Complainants state that the difference between the method used by their witness and the method used by the NETOs and Trial Staff is a minor one that does not materially affect any conclusion. Complainants further state that Dr. Woolridge's method of relying on dividend yields reported by a third-party source has an advantage over the other method in that the yields are available to and widely relied upon by investors.[129]

iii. Briefs Opposing Exceptions

74. NETOs agree with the Presiding Judge's determination that Dr. Avera calculated the dividend yields in accordance with Commission policy.[130] NETOs also agree with the Presiding Judge's rejection of Dr. Woolridge's dividend yield calculations because they contain a serious methodological error.[131] NETOs contend that, while Complainants seek to salvage Dr. Woolridge's dividend yields by asserting that his method is "consistent with practices that the Commission has applied in performing its own dividend yield analyses," the cases Complainants cite are contrary to this argument. NETOs argue that the Complainants' attempt to minimize the error by claiming that the difference between Dr. Avera's and Dr. Woolridge's approaches is "immaterial." NETOs further argue that the Appendix that the Complainants attach to their brief, which

---

[128] Initial Decision, 144 FERC ¶ 63,012 at P 562 (citing *Appalachian Power Co.*, 83 FERC at 62,350 (where the Commission cited its policy that dividend yields should be based upon the average high and low dividend yield for the six-month period)).

[129] Complainants Brief on Exceptions at 93.

[130] NETOs Brief Opposing Exceptions at 53-54.

[131] *Id.* at 56.

substitutes Dr. Avera's dividend yield data for Dr. Woolridge's, only addresses the April 17, 2013 proxy group, upon which Dr. Woolridge no longer relies. NETOs further state that the Appendix only shows Dr. Avera's dividend yields for the companies that are common to both proxy groups. They note that the one company missing from the Appendix, Unisource Energy Corp. (Unisource Energy), is the company that forms the high end of Dr. Woolridge's proxy group. Finally, NETOs argue that the dividend yield for Unisource Energy shown in Dr. Woolridge's analysis is incorrect, and thus Dr. Woolridge's April 17, 2013 DCF range and midpoint are wrong.[132]

iv. Commission Determination

75. As discussed in the preceding section, the dividend yield calculations in this case should be based on financial data for the six-month period ending March 2013.[133]

76. While the parties dispute the Presiding Judge's determination regarding the calculation of high and low dividend yields, that issue is mooted by our application of the two-step DCF methodology to public utilities. The two-step DCF methodology does not require the calculation of high and low dividend yields; rather, it requires the calculation of a single dividend yield for each member of the proxy group.[134] However, we do agree with the Presiding Judge that the Complainants improperly based their dividend yield calculations on the monthly dividend yields reported by *AUS Utility Reports*, which apparently calculates those yields based on the daily share price at the middle of each month. Rather than rely on dividend yields published in a newsletter that has not been shown to be widely relied on by investors, we find that it is more accurate to directly calculate dividend yields based on actual stock prices reported by the New York Stock Exchange or NASDAQ, and the company's own indicated dividends. Moreover, we find that our reliance on an average of the high and low stock prices for each month, as described below, produces a dividend yield that is more representative of financial

---

[132] *Id.* at 56-58 (citing *Consumers Energy Co.*, 98 FERC ¶ 61,333, at 62,416 (2002); *Orange & Rockland Utils., Inc.*, 40 FERC ¶ 63,053, at 65,202 (1987) (calculating the average monthly dividend yield for each month), *on exceptions*, Opinion No. 314, 44 FERC at 61,953, n.17, *order on reh'g*, Opinion No. 314-A, 45 FERC ¶ 61,252; *Conn. Light & Power Co.*, Opinion No. 305-A, 45 FERC ¶ 61,370, at 62,162 (1988) (calculating the average of the high stock prices for each month and the average of the low stock price for each month)).

[133] Initial Decision, 144 FERC ¶ 63,012 at P 559 (citing Ex. NET-300 at 30; Ex. NET-304 at note (a); Ex. NET-702 – UPDATED at note (a)).

[134] *See* Opinion No. 510, 134 FERC ¶ 61,129 at PP 232-234.

conditions during the entire month than is the *AUS Utility Report's* reliance on a single day's stock price from the middle of the month.

77. Accordingly, we find that the dividend yields of the proxy companies in this case should be calculated in the same manner that the Commission has consistently calculated dividend yields when applying the two-step DCF methodology. That methodology derives a single dividend yield for each proxy group company, using a three step process: (1) averaging the high and low stock prices as reported by the New York Stock Exchange or NASDAQ for each of the six months in the study period; (2) dividing the company's indicated annual dividend for each of those months[135] by its average stock price for each month (resulting in a monthly dividend yield for each month of the study period); and (3) averaging those monthly dividend yields.

78. As the Commission found in *Portland*, the method described above for calculating dividend yield for the two-step DCF methodology is an appropriate method of calculating the average dividend yield because "it matches each average monthly stock price with the actual dividend paid for that month to calculate the actual dividend yields for each of the preceding six months."[136] As the Commission also noted in *Portland*, this method is preferable to calculating the estimated dividend yield for each proxy group member based only on the dividend declared in the final month of the period. Using only the dividend declared in the final month results in a mismatch between the stock prices and the dividends used to calculate a firm's dividend yield. This can result in overstated dividend yields, particularly when a firm raises it dividends or distributions during the six-month study period, because earlier stock prices do not reflect the increased value of the stock resulting from the increased dividend or distribution.[137]

2. <u>Acceptable Sources of Analyst Growth Rate Data</u>

i. <u>Initial Decision</u>

79. For the prospective period, the Presiding Judge adopted the NETOs' growth rate estimates from the October 2012 to March 2013 study period,[138] which were based on

---

[135] In Opinion No. 510, the Commission approved the use of the most recent dividend declared by the relevant company to determine the "indicated annual dividend" for each of the six months.

[136] Opinion No. 510, 134 FERC 61,129 at P 234.

[137] *Id.* P 234.

[138] Initial Decision, 144 FERC ¶ 63,012 at P 565.

five-year IBES growth rates published by *Yahoo! Finance*.[139] The Presiding Judge noted that the Commission has previously relied on IBES growth rate projections published by *Yahoo! Finance* for many years.[140] The Presiding Judge also adopted the NETOs' position that, in order for an IBES growth projection to be used, *Yahoo! Finance* must indicate that at least two analysts cover the electric utility in question.[141] The Presiding Judge rejected Trial Staff's proposal to use growth projections from the Reuters Estimates Database (RED) when necessary, to assure that the growth projection is based on the estimate of more than one analyst.

80. Consistent with the Presiding Judge's holdings on the appropriate sources of analyst growth projections, the Presiding Judge adopted the NETOs' proposed 8.07 percent IBES growth projection in *Yahoo! Finance* for UIL Holdings. The Presiding Judge rejected Trial Staff's proposed 6.03 percent growth projection for UIL Holdings based on the average of two analyst growth projections in RED, one of 4.0 percent and one of 8.07 percent. The Presiding Judge agreed with the NETOs that it was more likely than not that the 4.0 percent growth projection in RED was a stale projection from one year ago, because RED indicated that the mean growth projection from one year before was 4.0 percent. The Presiding Judge further found that, whether only one or two analysts projected 8.07 percent growth for UIL Holdings, the fact that growth projection was reported in both IBES and RED was sufficient to confirm its use in this proceeding.[142]

ii. <u>Briefs on Exceptions</u>

81. Trial Staff takes issue with exclusive reliance on IBES analyst growth rate estimates published by *Yahoo! Finance*, arguing that the estimates are unreliable and stale.[143] Trial Staff states that *Yahoo! Finance* does not provide information regarding the number of analysts contributing to the IBES growth projection or the date of the growth projections. However, Trial Staff states, Thomson Reuters on Demand, which publishes the same IBES growth projections as *Yahoo! Finance*, also provides both the number of analysts contributing to each IBES growth projection and the age of those

---

[139] *Id.* P 552.

[140] *Id.* P 566.

[141] *Id.* P 544.

[142] *Id.* P 596 n.85.

[143] Trial Staff Brief on Exceptions at 62-66.

projections. Trial Staff argues that the use of a single analyst growth rate projection is inconsistent with the Commission's preference for consensus, two-analyst estimates.[144] Therefore, Trial Staff contends that, when Thomson Reuters on Demand indicates that the IBES growth rate reflects the view of only one analyst, the RED mean analyst growth rate should be used instead. Trial Staff states that RED is published on Thomson Reuter's website *reuters.com*, which is a free public website with different employees from Thomson Reuters on Demand. That website provides (1) RED analyst growth estimates, (2) the number of analysts contributing to the mean estimate, (3) the high and low estimate, and (4) the mean estimate one year ago.

82. Trial Staff argues that the Initial Decision contains no citations to support the Presiding Judge's finding that Commission policy mandates use of IBES data to the exclusion of any other source. Further, Trial Staff states that in Opinion No. 489 the Commission noted that the presiding judge in that case was not precluded "from finding candidates for inclusion in the proxy group for which comparable data can be reasonably substituted for the growth rate data reported by IBES."[145] Trial Staff argues that the Commission has not specifically addressed the quality of the growth rate estimates as sourced from the *Yahoo! Finance* website and for this reason the Commission has never previously determined whether another source should also be used when IBES data turns out to be stale or not based on consensus estimates.[146]

83. Complainants similarly contend that although the Commission has previously referenced IBES forecasts obtained from *Yahoo! Finance*, it has made clear that this approval is not exclusive of other credible sources.[147] Complainants contend that Trial Staff's approach of turning to Reuters when IBES reports only one analyst's long-term growth estimate is a better way to handle the unprecedented circumstance of a single analyst's forecast which threatens to drive the high or low cost of equity estimate.[148]

---

[144] *Id.* at 67-69.

[145] *Id.* at 64-65 (citing Opinion No. 489, 117 FERC ¶ 61,129 at P 8, *order on reh'g*, 122 FERC ¶ 61,265, *order granting clarification*, 124 FERC ¶ 61,136 (2008)).

[146] Trial Staff Brief on Exceptions at 66 (citing *Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at PP 83-84 (conditionally allowing, but not requiring, reference to growth forecasts published by Yahoo), *reh'g denied*, 123 FERC ¶ 61,259 (2008)).

[147] Complainants Brief on Exceptions at 71.

[148] *Id.* at 72-73.

84. Trial Staff, Complainants, and the EMCOS also oppose the Presiding Judge's acceptance of the NETOs' proposal to use the IBES 8.07 percent growth rate for UIL Holdings. Trial Staff states that the use of a single analyst's growth rate projection for UIL Holdings is inconsistent with the NETOs' assertion that a public utility must be covered by two analysts to be included in the proxy group.[149] Trial Staff also disagrees with the Presiding Judge's conclusion that RED data supports the latest IBES growth projection for UIL Holdings of 8.07 percent. Trial Staff states that the RED data indicates a proper consensus growth estimate of 6.03 percent, based on two analysts' estimates, one of 8.07 percent and one of 4.0 percent. Trial Staff also disputes the Presiding Judge's conclusion that the 4.0 percent growth rate estimate is stale.[150] While the RED data shows that the estimate for one year ago was 4.0 percent, it does not state that the current 4.0 estimate is the same year-old estimate. Moreover, Trial Staff argues that the time periods for the growth rate estimates and the dividend yields were not synchronized, and that this could lead to distorted results.[151]

85. Complainants and EMCOS argue that the Presiding Judge's reliance on the UIL Holdings IBES growth rate from *Yahoo! Finance* was in error since it was based on a single analyst's estimate, the estimate was attributed too much weight, the application of the estimate was asynchronous with the dividend yields period, and an adjustment should have been made to avoid double-counting transmission incentives.[152] EMCOS further argues that the Presiding Judge erred in not using growth rate sources that it put forth for UIL Holdings, including Zacks and DailyFinance.com.[153]

iii. <u>Briefs Opposing Exceptions</u>

86. The NETOs argue that the Presiding Judge was correct to accept their use of IBES growth rate estimates from *Yahoo! Finance*, because the Commission has routinely relied on *Yahoo! Finance* as a source of IBES growth rate data.[154] The NETOs state that the

---

[149] Trial Staff Brief on Exceptions at 67-70.

[150] *Id.* at 70-72.

[151] *Id.* at 73-74.

[152] Complainants Brief on Exceptions at 67-78; EMCOS Brief on Exceptions at 25-27.

[153] EMCOS Brief on Exceptions at 24.

[154] NETOs Brief Opposing Exceptions at 34.

Presiding Judge was correct to adopt the NETOs' proxy group screening criteria requiring that all proxy group members be "[e]lectric utilities that are covered by at least two industry analysts."[155] However, the NETOs state, this requirement does not mean that the IBES growth projection must be based on growth projections of more than one analyst. The NETOs explain that *Yahoo! Finance* indicates how many analysts cover a particular electric utility, but it does not identify the number of analysts contributing to its growth rate estimates.[156] Nevertheless, the Commission has consistently relied on IBES growth projections in *Yahoo! Finance* and has never required that IBES growth rates used in the DCF calculation be based on estimates provided by two analysts, and the Commission did not require it in *Atlantic Path15* or *Southern California Edison* or any other case.

87. NETOs also take issue with Trial Staff's reliance on data from RED, noting that the Commission will rely on such data only when IBES data is not available.[157] NETOs support the Presiding Judge's use of the most recent growth rate data even though it was submitted after the deadline for submitting final DCF results, because the Presiding Judge allowed parties to submit additional testimony on the issue.[158] NETOs argue that the more recent data on UIL Holdings indicates that the investment community changed its view of UIL Holdings's growth prospects.[159] NETOs disagree with Trial Staff that there was an inconsistency between the UIL Holdings growth rate and dividend data used in the DCF analysis; that the Presiding Judge used the wrong updated data; that two sources of long-term growth data are required for a company to remain in the proxy group; and that the Commission should reject the use of *Yahoo! Finance* growth estimates in this proceeding.[160] Finally, NETOs argue that the Commission should affirm the Presiding Judge's rejection of the Complainants' incentive adjustment to UIL Holdings's growth rate.[161]

---

[155] *Id.* at 16 (emphasis removed).

[156] *Id.* at 16-19.

[157] *Id.* at 35-36 (citing *Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at P 84).

[158] NETOs Brief Opposing Exceptions at 38-39.

[159] *Id.* at 40.

[160] *Id.* at 41-44.

[161] *Id.* at 50.

iv. Commission Determination

88. We affirm the Presiding Judge's adoption of the NETOs' five-year IBES growth rate data contained in its witness's April 26, 2013 testimony. The growth rate used in the DCF model should be the growth rate expected by the market. That growth rate may not necessarily prove to be the correct growth forecast, but the cost of common equity to a regulated enterprise depends upon what the market expects, not upon what ultimately happens. Accordingly, it is appropriate to look to the most recent record evidence of the growth rates actually expected by the investment community.[162]

89. The Commission has long relied on IBES growth projections as evidence of the growth rates expected by the investment community.[163] Since the discontinuation of the IBES Monthly Summary Data Book in 2008, the Commission has consistently used IBES growth rate estimates published by *Yahoo! Finance* as the source of analysts' consensus growth rates.[164] The NETOs have provided the requisite IBES growth rate figures published by *Yahoo! Finance* for every company in the national proxy group we adopt later in this order.[165]

90. We reject Trial Staff's proposal to use RED growth projections published by *reuters.com* for some of the proxy companies in place of the *Yahoo! Finance* IBES growth projections. Although the Commission has previously stated that "comparable data can be reasonably substituted for the growth rate data reported by [IBES] or Value

---

[162] *See Kern River*, 126 FERC ¶ 61,034 at P 120; *Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at P 73; *Transcon. Gas Pipe Line Corp.*, 85 FERC at 61,268-69.

[163] *See, e.g.*, *RITELine Ill., LLC*, 137 FERC ¶ 61,039, at P 68 (2011); *N. Pass Transmission LLC*, 134 FERC ¶ 61,095, at P 46 (2011); *Pub. Serv. Elec. & Gas Co.*, 126 FERC ¶ 61,219, at P 62 (2009); Opinion No. 445, 92 FERC at 61,257.

[164] *See, e.g.*, *N. Pass Transmission LLC*, 134 FERC ¶ 61,095 at P 52 (approving proxy selection criteria that required available IBES and Value Line data); *RITELine Ill., LLC*, 137 FERC ¶ 61,039 at P 71; *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281, at P 92 (2009); *Pub. Serv. Elec. & Gas Co.*, 126 FERC ¶ 61,219 at P 62 (approving a screen which excluded companies for which no IBES or Value Line data is available).

[165] The workpapers provided by the NETOs' witness do not include an IBES growth projection for CH Energy Group, and therefore that company will not be included in the proxy group. *See* Ex. NET-702 – UPDATED; NETOs, "Workpapers for the Respondents' Supplemental Testimony of Dr. William Avera under EL11-66" (dated Apr. 19, 2013).

Line" when the IBES growth rate figures are not available,[166] that is not the case here, because the NETOs have provided IBES growth data for all relevant companies. The Presiding Judge correctly found that the Commission has never required that there be two (or more) analysts' long-term growth rates for a company in order for it to be included in a proxy group. Trial Staff has only provided RED growth estimates for the few companies for which it asserts the IBES growth projection only reflects the view of one analyst. As a result, it is not possible to use RED growth estimates for all the companies in the proxy group. We find that an alternate source of growth rate data should only be used when that source can be used for the growth projections of all of the proxy group companies. Using different sources of growth rate data for different companies in a proxy group could produce skewed results, because those sources may take different approaches to calculating growth rates. Moreover, while the sources of growth rate data often rely on many of the same analysts in publishing their estimates, the different sources may use slightly different time periods from one another. For this reason, the Commission has consistently used a single investor service such as IBES for the investment analysts' growth rate estimate.[167] Therefore, while we reaffirm that there may be more than one valid source of growth rate estimates, in order to ensure that growth rate estimates are internally consistent in an ROE analysis we find it inappropriate to use estimates from different sources for different proxy group companies.

91. Consistent with the above discussion, we also find that the Presiding Judge correctly adopted the NETOs' proposed 8.07 percent IBES growth projection in *Yahoo! Finance* for UIL Holdings. While Thomson Reuters on Demand indicates that the UIL Holdings IBES growth rate reflects the view of only one analyst, we are not persuaded that investors would place less weight upon that IBES growth rate than the other IBES growth projections in *Yahoo! Finance*, which Trial Staff recognizes is a popular website for investors.[168]

B. <u>Composition of the Proxy Group</u>

92. In this section we address the following issues concerning the proper methodology for developing a proxy group and calculating the zone of reasonableness: (1) the use of a national group of companies considered electric utilities by Value Line; (2) the inclusion

---

[166] *See, e.g.*, *ISO New England, Inc.*, 109 FERC ¶ 61,147, at P 205 (2004); *ISO New England, Inc.*, 110 FERC ¶ 61,111, at P 23 (2005).

[167] *See, e.g.*, *RITELine Ill., LLC*, 137 FERC ¶ 61,039 at P 68; *N. Pass Transmission LLC*, 134 FERC ¶ 61,095 at P 46; *S. Cal. Edison Co.*, 92 FERC at 61,263.

[168] Trail Staff Brief on Exceptions at 62.

of companies with credit ratings no more than one notch above or below the utility or utilities whose rate is at issue; (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut during the six-month study period; (4) the inclusion of companies with no major merger activity during the six-month study period; and (5) companies whose DCF results pass threshold tests of economic logic.

1. National Proxy Group vs. Regional Proxy Group

i. Initial Decision

93. The Presiding Judge found it appropriate to use a national proxy group, rather than a regional proxy group, explaining that "the current financial and market conditions are better served by use of a more diverse national proxy group."[169] The Presiding Judge adopted the national proxy group produced by the NETOs' DCF analysis. The Presiding Judge noted that, although Opinion No. 489 happened to involve use of a regional proxy group, the Commission did not expressly prohibit use of a national proxy group, and that the Commission has found national proxy groups preferable.[170] However, the Presiding Judge agreed with the NETOs that, because several of the NETOs either do not have credit ratings or have Moody's credit ratings two notches lower than their S&P credit ratings, a national proxy group is more reflective of the NETOs than is a regional proxy group.[171] The Presiding Judge found that the NETOs' proxy group substantially complies with Commission precedent,[172] but that Trial Staff's proxy group was deficient because it relied primarily on companies that are significantly larger than most of the NETOs.[173]

ii. Briefs on Exceptions

94. EMCOS argues that using a large national proxy group could include outliers that will skew the ROE analysis, and that this concern is even more pressing when using the

---

[169] Initial Decision, 144 FERC ¶ 63,012 at P 551 n.49.

[170] *Id.*

[171] *Id.*

[172] *Id.* P 553 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at PP 32, 51 (using same proxy group criteria as Dr. Avera, but also requiring minimum revenues of $1 billion, which is inapplicable here given the NETOs' sizes).

[173] Initial Decision, 142 FERC ¶ 63,007 at P 554.

midpoint as the measure of central tendency.[174] Trial Staff argues that the Commission has never applied a national proxy group to estimate the base ROE for a diverse group of utilities[175] and Commission policy favors the use of a regional proxy group.[176] Trial Staff argues that its regional proxy group is the best reflection of the appropriate quality, span, and distribution of the NETOs' diverse risks.[177] Trial Staff further argues that pivotal issues in the Initial Decision include recognition of both S&P and Moody's credit ratings, and Ms. Lapson's presumption that unrated entities should be presumed to have near-junk or junk ratings of BBB- and lower.[178] Trial Staff explains that the Commission has found that it is appropriate to use a corporate credit rating screen of all investment grade companies when an applicant has no credit rating of its own.[179] Trial Staff argues that the Presiding Judge and the NETOs both failed to establish any relationship between the Morningstar market capitalization theory and the *Hope* and *Bluefield* goals, nor did they establish how "size" should be weighed against credit ratings in evaluating risk in this case. Trial Staff contends that the record does not support "size" as a superior criterion to credit ratings for determining a company's business and financial risk, and argues that credit ratings are the superior measure for developing comparable risk proxy groups.[180]

iii. <u>Briefs Opposing Exceptions</u>

95. The NETOs argue that the Presiding Judge correctly ruled that Commission precedent favors the use of a national proxy group, and that their national proxy group is more representative of the NETOs than Trial Staff's regional group.[181] NETOs contend that Trial Staff's regional proxy group selection is inappropriate because: (1) it cannot

---

[174] EMCOS Brief on Exceptions at 29-30 (citing *S. Cal. Edison Co.,* 137 FERC ¶ 61,016 at P 21, *aff'd sub nom. S. Cal. Edison Co. v. FERC,* 717 F.3d 177).

[175] Trial Staff Brief on Exceptions at 18.

[176] *Id.* at 18-19.

[177] *Id.* at 44.

[178] *Id.* at 40.

[179] *Id.* at 37-41 (citing *Atl. Grid Operations A LLC*, 135 FERC ¶ 61,144 at P 88 n.55).

[180] Trial Staff Brief on Exceptions at 30-31.

[181] NETOs Brief Opposing Exceptions at 6-7, 22-23.

fairly be called a regional proxy group for New England; (2) the Commission has never rejected a DCF study using a national proxy group; (3) there is no economic basis for comparable risk to be tied to the measure of central tendency; (4) the NETOs must compete for equity capital with utilities world-wide; and (5) it is not representative of the NETOs' business and financial risks.[182]

iv. Commission Determination

96. We find that it is appropriate to use a national proxy group, and we therefore affirm the Initial Decision's adoption of the NETOs' national proxy group.[183] Whether it is more appropriate to use a national proxy group or a regional proxy group is a question of capital attraction and comparability of risk.[184] We agree that "the NETOs must compete for capital with other utilities (and companies in other sectors) throughout the nation,"[185] and that investors are not limited to investments in geographically adjacent states but instead participate in national or international capital markets.[186] If the NETOs' ROE is significantly less than the returns of utilities in other parts of the nation, capital will more readily flow to areas other than New England and the NETOs may not be able to attract sufficient capital consistent with the *Hope* and *Bluefield* standards. Further, widening the geographic range of the proxy group allows for the application of more stringent screening criteria, to refine the proxy group to a level of risk more comparable, while maintaining a group of proxy companies that is sufficiently large and diverse to reliably capture the range of reasonable returns.[187] Moreover, in determining

---

[182] *Id.* at 7-11.

[183] *See* Initial Decision, 144 FERC ¶ 63,012 at P 541 n.49.

[184] *See generally Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at P 48 ("[T]he purpose of the proxy group is to 'provide market-determined stock and dividend figures from public companies comparable to a target company for which those figures are unavailable.['] . . . It is thus crucial that the firms in the proxy group be comparable to the regulated firm whose rate is being determined. In other words, as the court emphasized in *Petal*, the proxy group must be 'risk-appropriate.'") (quoting *Petal Gas Storage, L.L.C. v. F.E.R.C.*, 496 F.3d 695, 699 (D.C. Cir. 2007) (*Petal Gas*)).

[185] *Proxy Group Policy Statement*, 123 FERC ¶ 61,048 at P 434.

[186] *Id.* P 443.

[187] *See* Initial Decision, 144 FERC ¶ 63,012 at P 71.

comparability of financial and business risks, financial data is much more probative than geographical proximity.[188]

2. Value Line Electric Utilities

i. Initial Decision

97. The Presiding Judge found that the NETOs' use of *Value Line*'s electric utilities list as a proxy screen is consistent with Commission policy.[189] The Presiding Judge found that the Complainants' proposed proxy group is deficient, because they required that each proxy group company be followed by multiple financial services companies, which the Commission has never required.[190]

ii. Briefs on Exceptions

98. Complainants argue that the Presiding Judge should have accepted their use of *AUS Utility Reports* instead of *Value Line* as a proxy group screen, as well as their elimination of proxy companies that do not derive at least 50 percent of their revenues from regulated electric operations[191]

iii. Briefs Opposing Exceptions

99. The NETOs state that the Presiding Judge properly rejected the Complainants' requirements that the proxy group members be included in *AUS Utility Reports* and derive 50 percent of their revenues from regulated electric utility operations. The NETOs argue that their proxy group criteria already screen out companies that investors do not consider to be electric utilities by excluding companies not included in *Value Line*'s electric utility industry group. The NETOs further argue that Dr. Woolridge's 50 percent

---

[188] *See S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 29 ("We are persuaded by the parties that using a national proxy group in this case complies with the *Hope* standard of risk that is necessary 'to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.'") (quoting *Hope*, 320 U.S. at 603).

[189] Initial Decision, 144 FERC ¶ 63,012 at P 552 (citing *Atl. Path 15, LLC*, 122 FERC ¶ 61,135 at P 20, *order on reh'g*, 133 FERC ¶ 61,153 (2010); *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at PP 32, 51).

[190] Initial Decision, 144 FERC ¶ 63,012 at P 554.

[191] Complainants Brief on Exceptions at 90-91.

electric revenue test does not follow the Commission's decision in Docket No. ER04-157. Specifically, the NETOs contend that UGI Corporation (UGI) was excluded in that case because its regulated electric utility revenues were less than 5 percent of its total revenues and it was not classified as an electric utility by *Value Line*. The NETOs claim that the Commission did not establish a bright line revenues test in that case, nor has it ever done so.[192]

iv. Commission Determination

100. We affirm the Initial Decision's use of *Value Line* data as a proxy group screen. The Commission has previously relied on *Value Line*'s electric utility group listing to determine whether a company's risks warrant its exclusion from the electric proxy group.[193] We reject the Complainants' use of *AUS Utility Reports* instead of Value Line. The Commission has never relied upon *AUS Utility Reports* and we are not persuaded that it is appropriate to do so now. Unlike *Value Line*, which is an investment-oriented publication, *AUS Utility Reports* is a service published primarily for regulators and is not typically relied upon by investors.[194]

101. We also reject the Complainants' requirement that a company derive at least 50 percent of its revenues from regulated electric utility operations. The Commission has never applied a percentage threshold related to revenue sources, as determined by *AUS Utility Reports* or any other outlet, beyond which a utility is no longer considered an electric utility. While the Complainants correctly state that the Commission in Docket No. ER04-157 excluded UGI because it "receive[d] less than 5 percent of its revenue from its regulated electric utility operations," and was primarily a gas company rather than an electric company,[195] the Commission did not establish a percentage threshold for revenue sources. The Commission instead focused on the fact that UGI's risk profile was

---

[192] NETOs Brief Opposing Exceptions at 19-21 (citing *Bangor Hydro-Elec. Co.*, 111 FERC ¶ 63,048, at PP 29, 58, 61 (2005), *order on initial decision*, Opinion No. 489, 117 FERC ¶ 61,129 at PP 34, 37-38, *order on reh'g*, 122 FERC ¶ 61,265, *order granting clarification*, 124 FERC ¶ 61,136 (2008)).

[193] *See Atl. Grid Operations A LLC*, 135 FERC ¶ 61,144 at P 96; *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 51.

[194] Ex. NET-300 at 116.

[195] Complainants Brief on Exceptions at 91.

"significantly different than the risk profile of an electric utility company and the other companies in the proxy group."[196]

102. We therefore find that the appropriate starting point for the two-step DCF methodology will be the 49 companies, from across the United States, that *Value Line* classifies as being in the electric utility industry.[197] We accept the *Value Line* industry classifications because *Value Line* is a widely-followed, independent investor service; as there may be other reliable sources that investors rely upon, we will not mandate the use of *Value Line* in all cases, and will consider the use of other sources shown to be reliable and commonly relied upon by investors.

3. Credit Ratings

i. Initial Decision

103. The Presiding Judge found that it was appropriate for the NETOs to screen their proxy group to exclude public utilities with corporate credit ratings more than one notch above and below the subject utilities to be appropriate for use in this case, because the Commission has used this as screening criterion in previous cases.[198] The Presiding Judge also found that Trial Staff disregarded this proxy group screen.[199]

ii. Briefs on Exceptions

104. Trial Staff states that it assessed the risk comparability of its regional proxy group using methods consistent with Commission precedent, and the NETOs' adherence to the one-notch risk band convention produces an inferior proxy group for the diverse companies that make up the NETOs.[200] Trial Staff contends that the Commission has

---

[196] Opinion No. 489, 117 FERC ¶ 61,129 at P 37, *order on reh'g*, 122 FERC ¶ 61,265, *order granting clarification*, 124 FERC ¶ 61,136 (2008).

[197] *See* NETOs, "Workpapers for the Respondents' Supplemental Testimony of Dr. William Avera under EL11-66" (dated Apr. 19, 2013).

[198] Initial Decision, 144 FERC ¶ 63,012 at P 552, n.51 (citing *RITELine Ill., LLC*, 137 FERC ¶ 61,039 at P 68 (using corporate credit ratings one notch above and below target); *N. Pass Transmission, LLC*, 134 FERC ¶ 61,095 at P 46; *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 51).

[199] Initial Decision, 144 FERC ¶ 63,012 at P 553.

[200] Trial Staff Brief on Exceptions at 34.

only applied the one-notch credit rating screen in establishing a base ROE for a single utility and that it should not be used with a diverse group of utilities because it would result in a five-notch band.[201] Trial Staff argues that the unique circumstances of a diverse group of utilities supports dollar-weighted credit rating analyses, and that the NETOs' proxy group is inappropriately skewed toward higher risk.[202] Further, Trial Staff contends that the NETOs' recognition of both S&P and Moody's credit ratings, and the NETOs' presumption that unrated entities should be presumed to have near-junk or junk ratings, are unprecedented and unsupported.[203] Complainants argue that the Presiding Judge erred in rejecting the Complainants' proxy group because it purportedly used screening criteria "foreign to the FERC jurisdiction."[204]

iii. <u>Briefs Opposing Exceptions</u>

105. The NETOs argue that Trial Staff's claim that the NETOs are "dominantly rated A-/BBB+" is based on a flawed assessment of the NETOs' credit ratings. The NETOs assert that a proper analysis shows that they have an average rating of approximately BBB. The NETOs contend that Trial Staff ignored the presence of unrated entities among the NETOs and failed to consider the fact that the Moody's credit ratings of three of the seven NETOs have an S&P rating two notches lower than their S&P ratings. The NETOs also assert that eight of the 12 NETOs are lower rated than Trial Staff assumes. The NETOs contend that investors rely on both S&P and Moody's ratings and would assign either the lower of the two ratings or the average of the two ratings.[205] The NETOs argue that the Commission does not adopt a specific credit rating for unrated entities, but instead defaults to a comparable risk band of all investment grade utilities.[206]

---

[201] *Id.* at 35-36.

[202] *Id.* at 37-39.

[203] *Id.* at 40-44.

[204] Complainants Brief on Exceptions at 88.

[205] NETOs Brief Opposing Exceptions at 23-24.

[206] *Id.* at 26-29 (citing *Atl. Grid Operations A LLC*, 135 FERC ¶ 61,144 at P 88 n.55).

iv. **Commission Determination**

106. We affirm the Initial Decision's finding that it is appropriate to exclude from the proxy group those utilities with corporate credit ratings more than one notch above or below the NETOs' credit ratings. We reject Trial Staff's argument that the precedent on the credit rating band screen is limited to cases involving single utilities and that the screen should not apply in a case involving multiple utilities. The purpose of the credit rating band screen is to include in the proxy group only those companies whose credit ratings approximate those of the utilities whose rate is at issue. For a diverse group of utilities with a range of credit ratings, that approximation may require a credit rating band spanning more notches than the three that are typical in single utility cases. Further, contrary to Trial Staff's assertion, the Commission has in the past permitted comparable risk bands as wide as five credit notches.[207]

107. We further find that ratings from both major credit ratings services should be considered when developing the comparable risk band. As the NETOs correctly state, investors rely upon credit ratings from both S&P and Moody's. Therefore, while the Presiding Judge's application of the credit rating screen using only S&P ratings is consistent with Commission precedent, basing the credit rating screen on data only from S&P does not necessarily provide an accurate estimate of the NETOs' risk. Thus, we find that, in applying the credit rating proxy group screen to exclude companies more than one notch above or below the NETOs' credit ratings, it is appropriate to use both the S&P corporate credit ratings and the Moody's issuer ratings *when both are available*.[208] If a company is more than one notch above or below the credit ratings of the utilities whose rates are at issue based on *either* the S&P ratings *or* the Moody's ratings, that company shall be excluded from the proxy group.

108. Based upon the NETOs' range of S&P credit ratings from A- to BBB, we affirm the Presiding Judge's finding that the appropriate S&P corporate credit rating band screen in this case spans the five notches from A to BBB-. Based upon the record data that the Moody's credit ratings for the NETOs range from A2 to Baa2, we find that the appropriate Moody's credit rating band screen spans the six notches from A1 to Baa3.[209]

---

[207] *See, e.g.*, *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248, at 62,240 n.79 (2008) ("For both projects, the Commission screened the proxy group for companies with corporate credit ratings of BBB- to A.").

[208] We will not require that a company have both S&P and Moody's ratings to be eligible for inclusion in a proxy group, and we will screen only on the available rating.

[209] We note that the credit rating bands are based on only those NETOs that have credit ratings from S&P or Moody's.

Four of the initial proxy group companies fall outside one or both of these credit rating bands and are, therefore, excluded from the proxy group. Specifically, we exclude MGE Energy because of its AA- S&P rating; NV Energy, Inc. and PNM Resources, Inc. because of their Ba1 Moody's ratings; and Unisource Energy because of its BB+ S&P rating and its Ba1 Moody's rating.

4. Dividend Payments and Cuts

i. Initial Decision

109. The Presiding Judge found that the NETOs appropriately screened from their proxy group any company that has not paid six months of dividends without a dividend cut.[210] The Presiding Judge also found that Trial Staff's and Complainants' proxy groups were deficient because they required that each proxy group member have paid dividends for three years without any cuts.[211]

ii. Briefs on Exceptions

110. Trial Staff states that the significance of the dividend yield screen is highlighted by the Commission's past practice and finance theory on the limitations of the DCF model. Trial Staff explains that its three-year dividend yield criterion is a non-issue because it did not distort the proxy group results or estimated ROE.[212] Complainants argue that the NETOs failed to consistently follow their own dividend yield criterion and kept Exelon Corp. (Exelon) in the proxy group with adjusted dividend yields of 6-7 percent, despite its announcement in February 2013 that it was cutting its dividend effective April 2013.[213]

iii. Briefs Opposing Exceptions

111. NETOs state that the Presiding Judge properly required each proxy group member to have paid six months of dividends and rejected Trial Staff's and Complainants' proposed requirement that each proxy group member have paid steady or rising dividends

[210] Initial Decision, 144 FERC ¶ 63,012 at P 552.

[211] *Id.* PP 553-554 (citing Opinion No. 501, 123 FERC ¶ 61,047, *order on reh'g*, 144 FERC ¶ 61,132).

[212] Trial Staff Brief on Exceptions at 44-47.

[213] Complainants Brief on Exceptions at 93 (citing Ex. S-5 at 2-3; Ex. S-7 at 48).

for three years.[214] NETOs state that a three-year dividend yield screen would ignore the fact that the DCF model is based on investors' expected return from the current dividend yield and growth, not historical dividend payments. NETOs argue that Complainants' assertion that the Commission excluded Williams Companies in two cases does not support the exclusion of Empire District here, because the Commission excluded Williams Companies due to its particular financial circumstances, not a dividend cut in the DCF analysis period. NETOs further contend Empire District temporarily suspended its dividend due to a one-time, extreme weather event, not because of financial distress.[215]

iv. Commission Determination

112. We affirm the Initial Decision's finding that it is appropriate to include a utility in the proxy group if it has paid six months of dividends and has not made or announced a dividend cut.[216] We agree with the NETOs that a three-year dividend yield screen would be inappropriate because the DCF model is based on investors' required return from current, not historical, estimates of dividend yield and growth. Accordingly, because Empire District's dividend cut took place outside the six-month study period in this proceeding, we find that it was appropriate for the Presiding Judge to include Empire District in the proxy group. However, Exelon announced during the six-month study period that it would be cutting its dividend in April 2013, and we will therefore exclude Exelon from the proxy group.

5. Merger and Acquisition Activity

i. Initial Decision

113. The Presiding Judge found that the NETOs correctly screened their proxy group to exclude companies with ongoing merger and acquisition (M&A) activity. The Presiding

---

[214] NETOs Brief Opposing Exceptions at 13 (citing Opinion No. 510, 134 FERC ¶ 61,129, *order on reh'g*, 142 FERC ¶ 61,198).

[215] NETOs Brief Opposing Exceptions at 14-16 (citing *Kern River*, 129 FERC ¶ 61,240; *High Island Offshore System, L.L.C.*, 110 FERC ¶ 61,043 (2005), *vacated and remanded on other grounds sub nom. Petal Gas*, 496 F.3d 695.

[216] *See* Opinion No. 510, 134 FERC ¶ 61,129, *order on reh'g*, 142 FERC ¶ 61,198.

Judge noted that this screen has been used by the Commission in previous cases, and is appropriate for use in this case.[217]

ii. <u>Commission Determination</u>

114. We affirm the Initial Decision's acceptance of the NETOs' M&A screen, as it is consistent with Commission precedent.[218] Our practice is to eliminate from the proxy group any company engaged in M&A activity significant enough to distort the DCF inputs.[219] In applying that screen to the two-step DCF methodology, we affirm the Presiding Judge's elimination of Entergy Corp. and ITC Holdings Corp. from the proxy group due to their ongoing merger activity with each other during the study period, and we eliminate CH Energy Group[220] due to its acquisition by Fortis.[221] While Northeast Utilities was involved in M&A activity in the recent past, the record does not indicate that the M&A activity was significant enough to distort the DCF inputs. Thus, we find that the Presiding Judge appropriately included Northeast Utilities in the proxy group, as it completed its merger with NSTAR on April 12, 2012. Similarly, we agree that it is unnecessary to eliminate Ameren Corp., which announced on March 14, 2013 the sale of its generation business to Dynegy, and CenterPoint Energy and OGE Energy Corp., which also announced on March 14, 2013 the formation of a large master limited partnership for their midstream businesses. No party presented evidence indicating that

[217] Initial Decision, 144 FERC ¶ 63,012 at P 552 (citing *RITELine Ill., LLC,* 137 FERC ¶ 61,039 at P 68 (applying a screen excluding companies with recent merger and acquisition activity); *N. Pass Transmission, LLC,* 134 FERC ¶ 61,095 at P 46; *S. Cal. Edison Co.,* 131 FERC ¶ 61,020 at P 51)).

[218] *RITELine Ill., LLC*, 137 FERC ¶ 61,039 at P 68 (applying a screen excluding companies with recent merger and acquisition activity); *N. Pass Transmission, LLC*, 134 FERC ¶ 61,095 at P 46; *S. Cal. Edison Co.,* 131 FERC ¶ 61,020 at P 51.

[219] *Bangor Hydro-Elec. Co.*, 111 FERC ¶ 63,048 at PP 67-68, *aff'd in relevant part*, 117 FERC ¶ 61,129 (2006); *see also Atl. Grid Operations A LLC*, 135 FERC ¶ 61,144 at P 88 n.55; *Kern River*, 126 FERC ¶ 61,034 at PP 79-81.

[220] We note that, as discussed above, CH Energy Group is also eliminated from the proxy group due to a lack of IBES growth rate data.

[221] We note that no party filed briefs opposing the NETOs' elimination of Entergy Corp. and ITC Holdings Corp. due to their then-pending merger, nor to the elimination of CH Energy Group due to its acquisition by Fortis. Moreover, no party filed briefs proposing to eliminate additional proxies due to ongoing M&A activity.

these companies' announcements at the end of the study period impacted the DCF results by distorting the companies' stock prices, dividends, or growth rates.

6. High-End Outliers

i. Initial Decision

115. The Presiding Judge found that the NETOs' criteria for screening high-end outliers substantially complies with Commission precedent.[222] The Presiding Judge stated that Commission precedent requires the exclusion of cost of equity results where they fail "fundamental tests of reasonableness and economic logic."[223] The Presiding Judge further stated that the Commission's high-end outlier test since 2004 has been to exclude from the proxy group any company whose cost of equity estimate is at or above 17.7 percent and whose growth rate is at or above 13.3 percent.[224] The Presiding Judge asserted that for the DCF model to work properly both the high-end proxy group members and the low-end members must be appropriate. The Presiding Judge rejected Trial Staff's criticisms of the NETOs' high-end proxy group members and found that the NETOs provided a reasonable basis to support the inclusion of those companies.

ii. Briefs on Exceptions

116. Complainants state that the Initial Decision's adherence to a static 17.7 percent test that originated in 2003 conflicts with its references to "flexibility" and current "economic conditions" in raising the low-end threshold. Complainants further state that under the relevant Commission precedent there is already significant flexibility built into the low-end outlier test. Complainants contend that the Commission has never stated that the 17.7 percent high-end threshold is a static standard, but instead adopted that threshold in the context of a specific record that is now a decade old. Complainants argue that the

---

[222] Initial Decision, 144 FERC ¶ 63,012 at P 571.

[223] *Id.* P 572 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 47; *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205).

[224] Initial Decision, 144 FERC ¶ 63,012 at P 572 (citing *ITC Holdings Corp.*, 121 FERC ¶ 61,229, at PP 28, 42 (2007); *Potomac-Appalachian Transmission Highline LLC*, 122 FERC ¶ 61,188, at P 100 (2008), *order on reh'g*, 133 FERC ¶ 61,152, at PP 20, 40, 64 (2010); *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 57; *S. Cal. Edison Co.*, 139 FERC ¶ 61,042, at PP 54, 60; *RITELine Ill., LLC*, 137 FERC ¶ 61,039 at PP 68-73; *N. Pass Transmission LLC*, 134 FERC ¶ 61,095 at PP 46, 52-54).

Initial Decision should have confronted the evidence as to the appropriateness of a more current and stringent test, and that cases cited do not support adhering to a 17.7 percent high-end outlier test given current financial conditions.[225] The Complainants contend that the Presiding Judge should have updated the 17.7 percent high-end outlier test based on the change in bond yields since 2003. They contend that the 17.7 percent ROE rejected as unsustainable and illogical in Opinion No. 489[226] exceeded the contemporaneous average yield on 30-year public utilities by a factor of 3.12. Applying that same factor to the public utility bond yield for the relevant time period in this case would produce a high-end outlier test of 12.46 percent. EMCOS states that the Initial Decision mischaracterizes and ignores their witness testimony on outlier issues. EMCOS also states that the Initial Decision erroneously applies a fixed numerical threshold to define sustainable growth.[227]

iii. <u>Briefs Opposing Exceptions</u>

117. The NETOs state that the Commission does not reject IBES growth rates based on subjective opinions of witnesses. The NETOs also contend that the growth rates in their proxy group were well below the 13.3 percent level that the Commission views as unreasonable.[228]

iv. <u>Commission Determination</u>

118. Because we are adopting a two-step DCF methodology for determining the ROE for public utilities, we find that the high-end outlier issue in this proceeding is moot. Under the two-step DCF methodology, it is unnecessary to screen the proxy group for unsustainable growth rates because the methodology assumes that the long-term growth

---

[225] Complainants Brief on Exceptions at 48-49; 82-85 (citing *ITC Holdings Corp.*, 121 FERC ¶ 61,229; *Potomac-Appalachian Transmission Highline LLC*, 122 FERC ¶ 61,188 at P 100, *order on reh'g*, 133 FERC ¶ 61,152 at PP 20, 40, 64; *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 57; *S. Cal. Edison Co.*, 139 FERC ¶ 61,042 at PP 54, 60; *RITELine Ill., LLC*, 137 FERC ¶ 61,039 at PP 68-73; *N. Pass Transmission LLC*, 134 FERC ¶ 61,095 at PP 46, 52-54).

[226] Opinion No. 489, 117 FERC ¶ 61,129 at P 24; *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205.

[227] EMCOS Brief on Exceptions at 30-37.

[228] NETOs Brief Opposing Exceptions at 33.

rate for each company is equal to GDP. As a result, no company in the proxy group we are adopting here has a composite growth rate under the two-step DCF methodology in excess of the 7.66 percent growth rate of PNM Resources, Inc., or an ROE in excess of the 11.74 percent ROE of UIL Holdings. And those percentages are well within any high-end outlier test we have previously applied in utility rate cases and are within the high-end outlier test advocated by the Complainants on exceptions.

7. Low-End Outliers

i. Initial Decision

119. The Presiding Judge found that the NETOs' criteria for excluding low-end outliers in this case substantially complies with Commission precedent,[229] which requires the exclusion of companies whose cost of equity estimates fail tests of reasonableness and economic logic.[230] The Presiding Judge noted that, although it may be reasonable to exclude any company whose low-end ROE estimate fails to exceed the average bond yield by about 100 basis points or more, a flexible application of the low-end outlier test is appropriate because the Commission has not established an economic rationale supporting strict application of the 100 basis point figure.[231]

ii. Briefs on Exceptions

120. Trial Staff states that the NETOs incorrectly followed the Commission's well-established rule for excluding any companies whose ROE results fail to exceed the six-month average Moody's bond yield for the relevant rating category by about 100 basis points. Trial Staff notes that the NETOs correctly eliminated four companies which were under the 100 basis points threshold, but argues that they should not have eliminated Edison International (Edison), which had a low-end result of 5.9 percent, since they did not eliminate Cleco, which had a low-end result of 6.0 percent. Instead, Trial Staff contends that the "natural break" is between the 2.7 percent low-end result of Pacific Gas & Electric and the 5.9 percent low-end result of Edison.

---

[229] Initial Decision, 144 FERC ¶ 63,012 at P 571.

[230] *Id.* P 572 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 57; *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205).

[231] Initial Decision, 144 FERC ¶ 63,012 at P 573 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 55).

iii. Briefs Opposing Exceptions

121. In reference to the inclusion of Edison's low-end DCF result, the NETOs argue that there is no strict rule requiring the exclusion of any low-end cost of equity estimate that fails to exceed the average bond yield by 100 basis points. The NETOs argue that the flexible application of the low-end outlier test is consistent "with the Commission directive that low-end DCF results should be eliminated if they are somewhat above the average bond yield, but still sufficiently low that an investor would consider the stock to yield essentially the same return."[232] The NETOs argue that it is appropriate to set the low-end outlier threshold for the refund period slightly more than 100 basis points above utility bond yields given the economic conditions and downward bias on utility bond yields during the relevant time period.[233]

iv. Commission Determination

122. As the Presiding Judge correctly explained, the Commission's low-end outlier test for the one-step DCF methodology in recent years has been to exclude any company whose low-end ROE fails to exceed the average bond yield by some amount of basis points, taking into account the company's ROE estimate relative to the estimates of the other proxy group companies.[234] The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt.[235] In public utility ROE cases, the Commission has used 100 basis points above the cost of debt as an approximation of this threshold, but has also considered the distribution of proxy group companies to inform its decision on which companies are outliers. As the Presiding Judge explained, this is a flexible test. We therefore affirm the Initial Decision in this respect.

123. Applying the low-end outlier test in the instant proceeding results in the elimination of three companies from the proxy group. The Moody's Baa average for the

[232] NETOs Brief Opposing Exceptions at 67 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 55).

[233] NETOs Brief Opposing Exceptions at 67.

[234] Initial Decision, 144 FERC ¶ 63,012 at P 573 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 55).

[235] *See S. Cal Edison Co.*, 92 FERC at 61,266.

six-month study period ending March 2013 is 4.61 percent. Therefore, we find it appropriate to exclude from the proxy group any company with a cost of equity estimate of approximately 5.61 percent or lower. Accordingly, we eliminate the following companies as low-end outliers: Edison (3.11 percent); Ameren Corp. (5.26 percent); and Public Service Enterprise Group Inc., whose 5.62 percent cost of equity estimate is an insignificant single basis point above the 100 basis point threshold. Our decision to exclude these companies from the proxy group is buttressed by the fact that there is a natural break between the cost of equity estimates of the companies we exclude from the proxy group and the lowest cost of equity estimate of the companies we include in the proxy group, i.e., the 7.03 percent cost of equity estimate of El Paso Electric Co. The 5.62 percent cost of equity estimate of Public Service Enterprise Group Inc, is only 101 basis point above the applicable bond yield, while the 7.03 percent cost of equity estimate of El Paso Electric Co. is 242 basis points above the applicable bond yield. Thus, there is a 141 basis point break between the companies we exclude from the proxy group as low-end outliers and the companies we include in the proxy group.

8. Summary

124. In summary, of the 49 companies in the NETOs' starting proxy group,[236] 11 companies fail the above proxy group screens and are, therefore, eliminated from the proxy group. We eliminate one company – CH Energy Group, Inc. – because no IBES growth rate data is available for that company.[237] We eliminate two companies – Entergy Corp. and ITC Holdings Corp. – due to M&A activity. We eliminate four companies – MGE Energy, Inc., NV Energy, Inc., PNM Resources, Inc., and Unisource Energy Corp.

---

[236] The 49 companies in our starting proxy group are as follows: ALLETE, Inc.; Alliant Energy Corp.; Ameren Corp.; American Electric Power Co., Inc.; Avista Corp.; Black Hills Corp.; CenterPoint Energy, Inc.; CH Energy Group, Inc.; Cleco Corp.; CMS Energy Corp.; Consolidated Edison, Inc.; Dominion Resources, Inc.; DTE Energy Co.; Duke Energy Corp.; Edison International; El Paso Electric Co.; Empire District Electric Co.; Entergy Corp.; Exelon Corp.; FirstEnergy Corp.; Great Plains Energy Inc.; Hawaiian Electric Industries, Inc.; IDACORP, Inc.; Integrys Energy Group, Inc.; ITC Holdings Corp.; MGE Energy, Inc.; NextEra Energy, Inc.; Northeast Utilities; NorthWestern Corp.; NV Energy, Inc.; OGE Energy Corp.; Otter Tail Corp.; Pepco Holdings, Inc.; PG&E Corp.; Pinnacle West Capital Corp.; PNM Resources, Inc.; Portland General Electric Co.; PPL Corp.; Public Service Enterprise Group Inc.; SCANA Corp.; Sempra Energy; Southern Company; TECO Energy, Inc.; UIL Holdings Corp.; Unisource Energy Corp.; Vectren Corp.; Westar Energy, Inc.; Wisconsin Energy Corp.; Xcel Energy, Inc.

[237] We note that CH Energy Corp. would also fail the M&A screen.

– because their credit ratings fall outside either the Moody's or S&P credit risk bands. We eliminate one company – Exelon Corp. – due to its dividend cut within the 6-month study period.[238] Lastly, we eliminate three companies – Ameren Corp., Edison International, and Public Service Enterprise Group Inc. – as low-end outliers.

125. After eliminating these 11 companies, 38 companies remain in our final proxy group.[239] Based on the record developed thus far in this proceeding, the zone of reasonableness produced by those 38 companies is 7.03 percent to 11.74 percent, as shown in the Appendix to this order.[240] As noted above, this is a tentative finding, based on the 4.39 percent GDP value we use in our DCF analysis,[241] and is subject to any further record evidence submitted in the paper hearing on the long-term growth issue.

C. Placement of the Base ROE within the Zone of Reasonableness

1. Initial Decision

126. The Presiding Judge agreed with the NETOs that the just and reasonable base ROE should be based on the market conditions during the relevant time period, but concluded that the DCF analysis considers market conditions.[242] Accordingly, the

---

[238] We note that Exelon Corp. would also be eliminated as a low-end outlier.

[239] The 38 companies in our final proxy group are as follows: ALLETE, Inc.; Alliant Energy Corp.; American Electric Power Co., Inc.; Avista Corp.; Black Hills Corp.; CenterPoint Energy, Inc.; Cleco Corp.; CMS Energy Corp.; Consolidated Edison, Inc.; Dominion Resources, Inc.; DTE Energy Co.; Duke Energy Corp.; El Paso Electric Co.; Empire District Electric Co.; FirstEnergy Corp.; Great Plains Energy Inc.; Hawaiian Electric Industries, Inc.; IDACORP, Inc.; Integrys Energy Group, Inc.; NextEra Energy, Inc.; Northeast Utilities; NorthWestern Corp.; OGE Energy Corp.; Otter Tail Corp.; Pepco Holdings, Inc.; PG&E Corp.; Pinnacle West Capital Corp.; Portland General Electric Co.; PPL Corp.; SCANA Corp.; Sempra Energy; Southern Company; TECO Energy, Inc.; UIL Holdings Corp.; Vectren Corp.; Westar Energy, Inc.; Wisconsin Energy Corp.; Xcel Energy, Inc.

[240] The DCF result for El Paso Electric Co. set the bottom of the zone at 7.03 percent, and the DCF result for UIL Holdings Corp. set the top of the zone at 11.74 percent.

[241] *See* Appendix (explaining our calculation of the 4.39 percent GDP value).

[242] Initial Decision, 144 FERC ¶ 63,012 at P 548.

Presiding Judge found it appropriate to set the just and reasonable rate at the midpoint of the zone of reasonableness,[243] and rejected the NETOs' contention that the base ROE should be set halfway between the midpoint and the top of the zone of reasonableness.[244]

127. The Presiding Judge rejected the NETOs' contention that the traditional DCF methodology understated their true cost of equity and that alternative methodologies should be considered.[245] The Presiding Judge noted, however, that the Commission may consider alternative methods if necessary to adjust the ROE based on the legal and policy considerations expressed in *Hope* and *Bluefield*.[246] The Presiding Judge stated that, if the ROE is set substantially below 10 percent for long periods of time, it could negatively impact future investment in transmission and thereby negatively impact operational needs, reliability, and ratepayers' future costs.[247] The Presiding Judge further noted that current capital market conditions are a relevant consideration in formulating the appropriate ROE in this proceeding.[248] The Presiding Judge also explained that all expert witnesses in this proceeding deviated from the traditional DCF analysis for a variety of reasons including, "to make pragmatic adjustments to the DCF economic analysis theory during a rather volatile and unstable economic period."[249]

2. <u>Briefs on Exceptions</u>

128. The NETOs assert that setting the just and reasonable base ROE depends on the facts of each case and, while the Commission generally uses the midpoint of the zone of reasonableness when establishing the base ROE for a diverse group of utilities, the Commission has acknowledged that the base ROE may be set above the midpoint when warranted.[250] The NETOs argue that it is appropriate to set the base ROE in this

---

[243] *Id.* PP 590-591.

[244] *Id.* P 591.

[245] *Id.* P 549.

[246] *Id.* P 575.

[247] *Id.* P 576.

[248] *Id.* P 580.

[249] *Id.* P 595.

[250] NETOs Brief on Exceptions at 22 (citing *S. Cal. Edison Co.*, 92 FERC ¶ 61,070).

proceeding halfway between the midpoint and the top of the zone of reasonableness. The NETOs assert that, in declining to set the base ROE halfway up the top half of the zone, the Initial Decision failed to consider the Commission's policy on transmission investment, the extraordinary conditions in the credit markets, and the results of other alternative benchmark methodologies to the electric utility DCF analysis.

129. The NETOs argue that the Initial Decision also erred by not taking into account the effect that the "highly unusual market conditions" had on the DCF results, and that unusually low interest rates caused "abnormal, low-end results that unrealistically depress the ROE midpoint."[251] The NETOs state that capital market conditions at the time of the proceeding were anomalous, that 10-year Treasury bond yields were the lowest they have been since 1941 and yields on public utility bonds have been at their lowest levels in over thirty years.[252]

130. The NETOs further contend that capital market conditions are expected to change significantly in the near-term,[253] and strict reliance on the DCF methodology will result in ROEs "that are insufficient to attract investment on reasonable terms."[254] The NETOs argue that once the Federal Reserve's Quantitative Easing program ends, "which may be in the very near future, interest rates can be expected to rise to more normal levels," and bond levels can be expected to increase.[255] The NETOs assert that the Commission should take into account the evidence regarding low interest rates, how those interest rates depressed the ROE midpoint, and how interest rates will rise in the near-term, and then set the ROEs in the upper range of the zone.[256] The NETOs assert that, because the DCF analysis is meant to reflect the rate of return needed to attract investors going forward, data showing increasing interest rates and cost of capital is particularly relevant.[257]

---

[251] NETOs Brief on Exceptions at 31–32.

[252] *Id.* at 33.

[253] *Id.* at 32.

[254] *Id.*

[255] *Id.* at 34.

[256] *Id.* at 32–33.

[257] *Id.* at 35.

131. The NETOs argue that five alternative benchmark methodologies—the capital asset pricing model (CAPM), risk premium analysis, natural gas pipeline ROE, non-utility DCF analysis, and expected earnings analysis—provide additional information that would benefit the Commission's ROE analysis by showing that the existing 11.14 percent base ROE is just and reasonable and that the DCF analysis alone produces distorted results.[258] The NETOs note that since all models have shortcomings, it is appropriate to test DCF results against a number of other models and benchmarks in order to arrive at the soundest conclusion possible.[259]

132. Trial Staff argues that the Presiding Judge erred in stating that, if the ROE is set substantially below 10 percent for long periods, it could negatively impact future investment in the NETOs.[260] Trial Staff argues that an unqualified numerical ROE "floor" is inappropriate and ignores the value of financial estimation techniques used to estimate the cost of capital.[261] Trial Staff further states that the 10 percent floor was in part based on state-allowed ROEs which the Commission has rejected in light of its exclusive jurisdiction in this area.[262] Trial Staff states that the DCF model is based on actual, observed market data, and that the testimony on the alternative methodologies is not probative.[263]

133. Complainants note that, because the cost of capital varies over time, allowed ROEs must vary over time in order to remain cost-based.[264] Complainants argue that the method adopted by the Initial Decision "is incapable of tracking actual capital costs when they fall substantially below 10 [percent]."[265] Complainants argue that the opinion

---

[258] *Id.* at 36-37.

[259] *Id.* at 38 (citing NET-300 at 47-49; *Distrigas of Mass. Corp.*, 41 FERC ¶ 61,205, at 61,550-51 (1987); *S. Cal. Edison Co.*, 92 FERC at 61,260-61,267).

[260] Trial Staff Brief on Exceptions at 57.

[261] *Id.*

[262] *Id.*

[263] *Id.* at 58–59.

[264] Complainants Brief on Exceptions at 78–79 (citing *Hope*, 320 U.S. at 615; *Bluefield*, 262 U.S. at 692-93).

[265] Complainants Brief on Exceptions at 79.

expressed in the Initial Decision that an ROE of less than 10 percent for long periods could negatively impact future investment has no basis, and that investment will not be impeded if the actual cost of equity falls below 10 percent.[266]

3. Briefs Opposing Exceptions

134. EMCOS and Trial Staff argue that the base ROE should not be set halfway between the midpoint and the top end of the zone of reasonableness, but should instead be set at the midpoint, consistent with the Commission's traditional DCF methodology. EMCOS state that the base ROE need not be adjusted upwards to counteract alleged distortions caused by the traditional DCF methodology and allegedly anomalous economic conditions, or to further the Commission's transmission investment policies. Trial Staff contends that the public policy considerations that NETOs argue require a base ROE above the midpoint are weighed in determining incentive rates, which are not at issue in this case. Similarly, EMCOS state that the traditional DCF methodology is designed to encourage transmission investment and ROE adders are available if the base ROE fails to do so.

135. Trial Staff asserts that the base ROE should be set according to cost of service ratemaking principles and should reflect investors' required return, i.e., the cost of equity capital. EMCOS states that the base ROE should be set based on current market conditions, not based on predictions that economic conditions could significantly change in the future. EMCOS states that the Commission has previously rejected the argument that current economic conditions are abnormal and have caused DCF results that are too low.[267] EMCOS further notes that should the NETOs' economic prediction come to fruition, they may then make a section 205 filing requesting a rate increase, but until then "rate payers should pay rates that reflect the actual economy."[268]

136. Trial Staff argues that the NETOs' proposed alternative methodologies do not result in a just and reasonable base ROE in this proceeding, due to flawed execution and unreliable or inappropriate data. Trial Staff explains that the Commission has consistently

---

[266] *Id.*

[267] EMCOS Brief Opposing Exceptions at 15 (citing Opinion No. 524, 142 FERC ¶ 61,197 at P 233).

[268] EMCOS Brief Opposing Exceptions at 15, 24–25.

rejected the proffered use of financial models other than the traditional DCF analysis.[269] Trial Staff contends that relying on past ROEs or risk premium relationships to impute an expected investor return today, as do some of the alternative methodologies, produces circular results that are theoretically inferior measures of current investor-required equity returns. Trial Staff further contends that, because the data used in the alternative methodologies are not screened based on relative risk, these methods also do not produce ROEs which are relevant to the NETOs' risks. Complainants argue that the Commission has continued to find that non-DCF approaches to determining transmission ROE are "unlikely to produce a just and reasonable result," and that its "preference for the one-step DCF analysis in determining the appropriate ROE for electric utility companies" is well-settled and recently reaffirmed.[270]

137. The NETOs agree with the Presiding Judge that, if the ROE is set substantially below 10 percent for long periods, it could negatively impact future investment, because "investors will expect a somewhat higher return for investment in transmission as compared to investment in state jurisdictional activities," due to the higher risks associated with transmission investment.[271] The NETOs argue that, because the central tendency of state-level ROEs has been around 10 percent to 10.5 percent, an ROE at or below these levels would materially reduce investment.[272] The NETOs assert that the Initial Decision did not establish an ROE floor of 10 percent, but instead simply found that there was "probative value to the argument that an ROE set below 10 [percent] could negatively impact future investment in the NETOs."[273]

---

[269] Trial Staff Brief Opposing Exceptions at 36-38 (citing *Allegheny Power,* Opinion No. 469, 106 FERC ¶ 61,241 P 24, *reh'g denied,* Opinion No. 469-A, 108 FERC ¶ 61,151 (2004), *dismissed in part vacated in part and remanded sub nom. Allegheny Power v. FERC,* 437 F.3d 1219 (D.C. Cir. 2006); *Sys. Energy Resources, Inc.,* Opinion No. 446, 92 FERC at 61,446; Opinion No. 445, 92 FERC at 61,260-63).

[270] Complainants Brief Opposing Exceptions at 57 (citing *Xcel Energy Servs., Inc.*, 122 FERC ¶ 61,098, at P 73, *clarified*, 125 FERC ¶ 61,092 (2008); Order No. 679, FERC Stats. & Regs. ¶ 31,222 at PP 99, 102).

[271] NETOs Brief Opposing Exceptions at 95 (citing Ex. NET-600 at 37-38; Tr. 454:25-455:3, 856:3-6; Ex. NET-400 at 26; Tr. 455:4-6, 855:23-856:9).

[272] NETOs Brief Opposing Exceptions at 96.

[273] *Id.* at 98 (citing Initial Decision, 144 FERC ¶ 63,012 at P 576).

138. Complainants argue that "Commission precedent requires 'highly unusual circumstances indicating anomalously high or low risk factors and a very persuasive demonstration' before a base ROE can properly be adjusted upwards from the center of the DCF results," and that NETOs' prediction of market changes falls short of these standards.[274]

139. Complainants take issue with NETOs' claim that low bond yields results in higher utility stock prices and lower dividend yields, arguing that "investors' comparison-shopping makes them willing to accept lower equity returns when debt yields are low."[275] Complainants argue that the DCF analysis process takes that effect into account and its doing so does not result in anything abnormal or unrealistic.[276]

140. Complainants take issue with NETOs' claim that the DCF-estimated ROE should be adjusted upwards due to anticipated interest rate increases since the core DCF method is to infer the return term from share prices paid in the past six months, and argues that "expectations about the pace and vigor of economic recovery, and of associated Federal Reserve monetary policy, are already baked into study-period share prices and analysts' forecasts of the proxies' future earnings."[277] Complainants argue that when the Commission *has* attributed a higher ROE than the DCF results, it was because the utility was substantially riskier than the proxies; but here, Complainants argue, the NETOs are less risky than the proxy group on which the Initial Decision relied and NETOs have "not made the 'very persuasive' showing of greater risk that precedent requires as a precondition to placing a base ROE above the DCF center."[278]

141. Complainants argue that predictions of capital market changes cannot justify raising the ROE in this proceeding.[279] Complainants take issue with NETOs' efforts "to shift the focus of this proceeding to the returns they expect will be demanded by the

---

[274] Complainants Brief Opposing Exceptions at 42 (citing Opinion No. 524, 142 FERC ¶ 61,198 at P 241).

[275] Complainants Brief Opposing Exceptions at 43–44.

[276] *Id.* at 44.

[277] *Id.* at 47–48.

[278] *Id.* at 48–49 (citing Opinion No. 524, 142 FERC ¶ 61,198 at P 241).

[279] Complainants Brief Opposing Exceptions at 49.

investors of 2017."[280] Complainants argue that, if NETOs' predictions are correct, it will have the opportunity to then file for a rate increase; the Commission's decision-making in the meantime, however, "requires reference to the DCF results of record, not predictions of how capital costs may rise by 2017."[281]

4. **Commission Determination**

142. We acknowledge that under the DCF analysis, the Commission typically sets the base ROE with regard to multiple entities at the midpoint of the zone of reasonableness. However, for the reasons set forth below, we conclude that a mechanical application of the DCF methodology with the use of the midpoint here would result in an ROE that does not satisfy the requirements of *Hope* and *Bluefield*. Therefore, based on the record in this case, including the unusual capital market conditions present, we conclude that the just and reasonable base ROE for the NETOs should be set halfway between the midpoint of the zone of reasonableness and the top of the zone of reasonableness. Based on the record thus far in this proceeding, we tentatively find that the just and reasonable base ROE for the NETOs is 10.57 percent, which is halfway between the 9.39 percent midpoint of the zone of reasonableness and the 11.74 percent top of that zone. This finding is tentative because it is subject to the submission of the record evidence at the paper hearing, described below, as to the appropriate long-term growth rate given our adoption of the two-step DCF methodology.

143. Having applied the DCF model and risk screens to develop a proxy group and estimate the zone of reasonable ROEs for similar companies – a zone of 7.03 percent to 11.74 percent – the Commission must next determine where to place the just and reasonable ROE within that zone of reasonableness. *Hope* once again sets forth the principle guiding this determination: the just and reasonable ROE should be "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[282]

---

[280] *Id.* at 50.

[281] *Id.*

[282] *Hope*, 320 U.S. at 603; *see also Bluefield*, 262 U.S. at 693 ("The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."). *Cf. supra* P 102 (describing the NETOs' competition with other utilities and other non-utility companies to attract capital).

144. While the Commission has previously found the midpoint of the zone of reasonableness to be the appropriate measure of central tendency for determining the base ROE for a diverse group of utilities (as opposed to the median, used for a single utility),[283] the midpoint does not represent a just and reasonable outcome *if* the midpoint does not appropriately represent the utilities' risks.[284] The Commission's ultimate task is to ensure that the resulting ROE satisfies the requirements of *Hope* and *Bluefield*.

145. Parties on both sides of the instant ROE issue argue that the unique capital market conditions have impacted the level of equity return the NETOs' require to meet the capital attraction standards of *Hope* and *Bluefield*.[285] We are concerned that capital market conditions in the record are anomalous, thereby making it more difficult to determine the return necessary for public utilities to attract capital. In these circumstances, we have less confidence that the midpoint of the zone of reasonableness established in this proceeding accurately reflects the equity returns necessary to meet the *Hope* and *Bluefield* capital attraction standards.[286] We find it is necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark

---

[283] *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 91, *remanded on other grounds sub nom. S. Cal. Edison Co. v. FERC*, 717 F.3d 177.

[284] *See Petal Gas*, 496 F.3d at 699.

[285] *See, e.g.*, Ex. C-1, 5-6 (Test. of Complainants' witness Woolridge); NETOs Brief on Exceptions at 32. For example, bond yields are at historic lows, with the yield on U.S. Treasury bonds during the six-month study period ending March 2013 below 2 percent. Ex. NET-405; Ex. NET-400 at 32-33. Until the financial crisis of 2008, the yield on U.S. Treasury bonds had not fallen below 3 percent since the 1950s. Ex. NET-450. U.S. Treasury bond yields are not an input in the DCF model, but they reflect current capital market conditions, which could have an indirect impact on the two inputs in the DCF model—dividend yield and growth rate.

[286] As the NETOs' witness Lapson testified, "There is 'model risk' associated with the excessive reliance or mechanical application of a model when the surrounding conditions are outside of the normal range. 'Model risk' is the risk that a theoretical model that is used to value real-world transactions fails to predict or represent the real phenomenon that is being modeled." Ex. NET-400 at 40.

methodologies and state commission-approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the resulting midpoint.[287]

146. The NETOs presented five alternative benchmark methodologies in this proceeding: risk premium analysis, the CAPM, comparison of electric ROEs with natural gas pipeline ROEs, comparison of electric utility DCF results with non-utility DCF results, and expected earnings analysis. Of those five, we find the risk premium analysis, the CAPM, and expected earnings analyses informative,[288] and each produces a midpoint (or median) ROE higher than the midpoint of our DCF analysis here. In considering these other methodologies, we do not depart from our use of the DCF methodology; rather, we use the record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness established in the record by the DCF methodology.

147. The risk premium methodology, in which interest rates are a direct input, is "based on the simple idea that since investors in stocks take greater risk than investors in bonds, the former expect to earn a return on a stock investment that reflects a 'premium' over and above the return they expect to earn on a bond investment."[289] As the NETOs explain, investors' required risk premiums expand with low interest rates and shrink at higher interest rates. The link between interest rates and risk premiums provides a helpful indicator of how investors' required returns on equity have been impacted by the

[287] *See, e.g., Distrigas of Mass. Corp.*, 41 FERC at 61,550 ("The DCF methodology, which we endorse, is but one analytical tool. A risk premium analysis, . . . will also be considered. The weight to be given the results of each such methodology rests on the accuracy and sensibleness of the judgmental imputs [*sic*] and factors that the respective witnesses employed."); *see also,* Roger A. Morin, New Regulatory Finance at 428-430 (Public Utilities Reports, Inc. 2006) (The results from one methodology . . . may be distorted by short-term aberrations.).

[288] We will not consider the non-utility DCF analysis or the natural gas pipeline ROE analysis because those methodologies are not based on electric utilities.

[289] Roger A. Morin, New Regulatory Finance 108 (Public Utilities Reports, Inc. 2006). CAPM estimates risk premiums indirectly, whereas the risk premium analysis methodology develops risk premiums directly. *Id.* at 110.

interest rate environment.[290] The NETOs' risk premium analysis indicates that the NETOs cost of equity is between 10.7 percent and 10.8 percent, which is higher than the 9.39 percent midpoint produced by our DCF analysis.[291] Similar to the risk premium analysis, the NETOs' CAPM uses interest rates as the input for the risk-free rate, which makes it useful in determining how the interest rate environment has impacted investors' required returns on equity.[292] Further, CAPM is utilized by investors as a measure of the cost of equity relative to its risk. Using the same proxy companies from our DCF analysis, before screening for low-end outliers, the NETOs' CAPM analysis produces an ROE range of 7.4 percent to 13.3 percent, with a midpoint value of 10.4 percent and a median value of 10.9 percent.[293] Finally, the NETOs' expected earnings analysis, given its close relationship to the comparable earnings standard that originated in *Hope*, and the fact that it is used by investors to estimate the ROE that a utility will earn in the future can be useful in validating our ROE recommendation.[294] Once again using the same proxy group that we used in our DCF analysis, the expected earnings analysis has an

---

[290] While the Commission has in the past rejected the use of risk premium analyses to estimate investor-required returns on equity, those cases are distinguishable from the instant proceeding because they involved proposals to establish a constant risk premium based on the average difference between state commission ROEs and bond rates over multi-year periods. *See New England Power Co.*, 31 FERC ¶ 61,378, at 61,841-42 (1985); *Boston Edison Co.*, Opinion No. 411, 77 FERC at 62,171-72, *aff'g in relevant part*, 66 FERC at 65,075-76, *remanded on other grounds sub nom. Boston Edison Co. v. FERC*, 233 F.3d 60 (2000); *Jersey Cent. Power & Light Co.*, 77 FERC at 61,007; *N. Ind. Pub. Serv. Co., Inc.*, 101 FERC ¶ 61,394, at P 38 (2002).

[291] *See* NETOs Brief on Exceptions at 44.

[292] While the Commission has in the past rejected the use of CAPM analyses, those cases are distinguishable from the instant proceeding because they involved CAPM analyses that were based on historic market risk premiums, *see, e.g., ITC Holdings Corp., et al. v. Interstate Power and Light Co. and Midwest Indep. Sys. Op., Inc.*, 121 FERC ¶ 61,229, at P 43 n.37 (2007), whereas the NETOs' CAPM analysis is based on forward-looking investor expectations for the market risk premium.

[293] Ex. NET-708. While NETO's exhibit does not provide a median value, we calculate it to be 10.4 percent using the 41 companies in our DCF analysis.

[294] Roger A. Morin, New Regulatory Finance 381 (Public Utilities Reports, Inc. 2006). The comparable earning standard uses the return earned on book equity by enterprises of comparable risk as the measure of fair return. *Id.*

ROE range of 8.1 percent to 16.1 percent, with a midpoint value of 12.1 percent and a median value of 10.2 percent.[295] The record evidence from each of these models affirms our setting the ROE at a point above the midpoint under these circumstances.

148. In addition, other record evidence of state commission-approved ROEs supports adjusting the ROE to a point halfway up the upper half of the zone of reasonableness in this case. The Commission has repeatedly held that it does not establish utilities' ROE based on state commission ROEs for state-regulated electric distribution assets, because those ROEs are "established at different times in different jurisdictions which use different policies, standards, and methodologies in setting rates."[296] The wisdom of that rationale is no less applicable now than in the Commission's earlier cases. However, in this proceeding, we are faced with circumstances under which the midpoint of the zone of reasonableness established in this proceeding has fallen below state commission-approved ROEs, even though transmission entails unique risks that state-regulated electric distribution does not. While the midpoint in this case is 9.39 percent, the record indicates that, over the 24-month period from October 1, 2010 through September 30, 2012, approximately 85 percent to 91 percent of state commission authorized ROEs were between 9.8 percent and 10.74 percent.[297] Although we are not using state commission-approved ROEs to establish the NETOs' ROE in this proceeding, the discrepancy between state ROEs and the 9.39 percent midpoint serves as an indicator that an upward adjustment to the midpoint here is necessary to satisfy *Hope* and *Bluefield*.

149. The financial and business risks faced by investors in companies whose focus is electric transmission infrastructure differ in some key respects when compared to other electric infrastructure investment, particularly state-regulated electric distribution. For example, investors providing capital for electric transmission infrastructure face risks including the following: long delays in transmission siting, greater project complexity, environmental impact proceedings, requiring regulatory approval from multiple jurisdictions overseeing permits and rights of way, liquidity risk from financing projects

---

[295] Ex. NET-709. While the NETOs' exhibit does not provide a median value, we calculate it to be 10.2 percent using the 41 companies in our DCF analysis.

[296] *Middle South Services, Inc.*, Opinion No. 124, 16 FERC ¶ 61,101, at 61,221 (1981); *see also Boston Edison Co.*, Opinion No. 411, 77 FERC ¶ 61,272, at 62,171-62,172 (1996); *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC at 61,002.

[297] Ex. NET-400 at 26-27 (citing Ex. NET-402; Ex. NET-403); *see also* Ex. NET-400 at 13 ("Individual transmission tariffs decided since 2006 have typically included base-level ROEs that . . . were within or above the high end of the range of returns available in state jurisdictions.").

that are large relative to the size of a balance sheet, and shorter investment history.[298] We find that these factors increase the NETOs' risk relative to the state-regulated distribution companies. However, as noted above, the record in this proceeding indicates that the vast majority of state commission-authorized ROEs reflected on this record range from 9.8 percent to 10.74 percent,[299] and our DCF analysis in this proceeding produces a midpoint of 9.39 percent, we find that the record evidence concerning state commission authorized ROEs supports setting the NETOs' base ROE above the midpoint.

150. Our obligation as a Commission is to ensure that we meet the requirements of *Hope* and *Bluefield* that ROE be set at a level sufficient to attract investment in interstate electric transmission. Such investment helps promote efficient and competitive electricity markets, reduce costly congestion, enhance reliability, and allow access to new energy resources, including renewables.[300] While a mechanical application of the two-step constant growth DCF methodology produces a midpoint of 9.39 percent in the anomalous capital market conditions reflected in the record, there is also record evidence that a decrease in ROE of that magnitude (down from 11.14 percent) could undermine the ability of the NETOs to attract capital for new investment in electric transmission.[301] As discussed above, a 9.39 percent ROE would be generally below the ROEs set by state commissions for electric utilities within their jurisdiction. Reducing the NETOs' ROE to that level "would put interstate transmission [investments] at a competitive disadvantage in the capital market in contrast with more conventional electric utility activities."[302] In addition, such a reduction in ROE could lead investors to view investments in interstate

[298] *See* Ex. NET-400 at 10-15, n.12; NETOs Brief Opposing Exceptions at 95-97.

[299] Ex. NET-400 at 26-27 (citing Ex. NET-402; Ex. NET-403).

[300] *See* Ex. NET-400 at 19-23 and 30-31.

[301] *Id*. at 16-19. For example, the NETOs' witness pointed out that a May 3, 2012 UBS Investment Research sector comment stated, "We believe companies will redeploy capital elsewhere if transmission returns are materially reduced. In our view, the cost of capital could actually increase, because as returns are set lower, valuation multiples will also be reset much lower than current levels. Additionally, the second order effects on other state and Federal government policy objectives, i.e. renewables development, could be significant, in our view." *Id*. at 18.

[302] *Id*. at 24.

transmission as more unstable, diminishing "investors' confidence in FERC jurisdictional investment in transmission."[303]

151. In these circumstances, we find that the NETOs should be awarded an ROE above the midpoint of the zone of reasonableness established by our DCF analysis. The Commission has traditionally looked to the central tendency to identify the appropriate return within the zone of reasonableness.[304] Similarly, we believe that here in selecting the appropriate return we likewise should look to the central tendency to identify the appropriate return but, in light of the record in this proceeding, we should look to the central tendency for the top half of the zone of reasonableness,[305] thus identifying an appropriate return reflective of capital market conditions in the record and the need to meet the capital attraction standards of *Hope* and *Bluefield*. And thus, we will set the NETOs' ROE at the point that is halfway between the midpoint of the zone of reasonableness and the top of the zone.[306]

---

[303] *Id*. at 43. *See also* Ex. NET-600 at 42 ("In my professional opinion, cutting the base ROE by approximately 150 basis points . . . would undermine the favorable access to capital that currently allows for and fosters major development of transmission infrastructure by transmission owners throughout the United States. Strong cash flow and healthy levels of return produce the corporate financial resources that allow utilities such as the NETOs to enter into multi-year commitments to fund major capital investments with both equity and debt, without regard to the cycles in capital and banking markets. . . .A steep reduction in base ROE will affect the capital market appeal of electric transmission investment by the NETOs and other utilities across the nation.").

[304] *See generally, e.g., Midwest Independent Transmission System Operator, Inc*., 106 FERC ¶ 61,302, at P 10 (2004) (given a range of returns, the "most appropriate" and "most just and reasonable" single return that best considers that range is the central tendency), *aff'd in relevant part sub nom. Pub. Serv. Comm'n of Ky. v. FERC*, 397 F.3d 1004, 1010-11 (D.C. Cir. 2005).

[305] *See infra* P 156 (explaining that the participants have had a full opportunity to submit evidence on the placement of the base ROE above the midpoint of the zone of reasonableness, and contest the evidence relied upon in our finding that it is appropriate to place the base ROE halfway between the midpoint of the zone of reasonableness and the top of that zone).

[306] Concurrently with this opinion we are setting for trial-type evidentiary hearings and settlement judge procedures other pending cases where the issue is the appropriate ROE. Nothing in this order precludes participants in those proceedings from developing a record in those cases supporting a different point in the range of reasonable returns than

(continued…)

152. In sum, based on the record evidence in this case, including the unusual capital market conditions present, we find that, to ensure a base ROE that satisfies the *Hope* and *Bluefield* standards under these circumstances, a base ROE in the upper half of the zone of reasonableness represents a just and reasonable base ROE for the NETOs. When placing a base ROE above the central tendency of the zone of reasonableness, the Commission has in the past placed the base ROE at the midpoint of the upper half of the zone.[307] We, therefore, find that a base ROE halfway between the midpoint of the zone of reasonableness and the top of that zone represents a just and reasonable ROE for the NETOs. Accordingly, based on the record evidence thus far in this proceeding, we tentatively find that a base ROE of 10.57 percent, the point halfway between the 9.39 percent midpoint of the zone of reasonableness and the 11.74 percent top of that zone, is appropriate for the NETOs. As noted, our finding concerning the specific numerical just and reasonable ROE for the NETOs is subject to the outcome of the paper hearing on the appropriate long-term growth projection to be used in the two-step DCF methodology.

153. EMCOS argues that the NETOs' base ROE should not be placed above the midpoint because the DCF methodology is designed to encourage transmission investment and ROE adders are available if the base ROE fails in that respect. Similarly, Trial Staff argues that it is inappropriate to place the NETOs' base ROE above the midpoint because the policy considerations for doing so are weighed in determining incentive rates. We reject both of these arguments. The purpose of the Commission's ROE analysis is to determine a level of return sufficient to satisfy *Hope* and *Bluefield*. Under that precedent, we are tasked with ensuring that the base ROE, among other things, enables the utility to attract investment. In contrast, ROE incentive adders are intended to encourage transmission investment above the level produced by a base ROE due to the circumstances of a certain project or projects. Although section 219 of the FPA gives us authority to provide incentives above the base ROE, nothing in section 219 relieves us from first setting the base ROE at a place that meets *Hope* and *Bluefield*. As

---

the midpoint of the upper half of the range. *See Transcon. Gas Pipe Line Corp.*, Opinion No. 414-A, 84 FERC ¶ 61,084, at 61,427-3 (1998) ("the Commission has determined that the parties to a rate proceeding may present evidence they believe is warranted to support any ROE that is within the DCF-derived zone of reasonableness. . . .").

[307] *See, e.g.*, Opinion No. 445, 92 FERC at 61,266; *Consumers Energy Co.*, Opinion No. 429, 85 FERC at 61,363-64. We note that the Commission has also in the past established the base ROE at the top of the zone of reasonableness, *see, e.g.*, Opinion No. 524, 142 FERC ¶ 61,197 at P 4; however, the record in this proceeding does not support, nor do the NETOs argue in favor of, setting the base ROE at the top of the zone.

shown above, our decision regarding the placement of the ROE in the zone meets that precedent.

D. <u>Establishment of Paper Hearing</u>

154. Because we change our approach to setting ROEs in this order, to now and henceforth use the two-step DCF methodology in determining the ROE for public utilities, and the parties did not address that methodology on the record, we will reopen the record for the limited purpose of allowing the participants to this proceeding an opportunity to present written evidence concerning one issue unique to the application of the two-step DCF methodology to the facts of this proceeding. Specifically, because the one-step DCF methodology does not include a long-term growth projection, the participants have not had an opportunity to present evidence concerning the appropriate long-term growth projection to be used for public utilities under the two-step DCF methodology. Therefore, we establish a paper hearing proceeding to provide the participants, including Trial Staff, the opportunity to submit additional evidence and argument concerning the limited issue of the appropriate long-term growth projection to be used in the two-step DCF methodology.

155. However, use of the two-step DCF methodology does not affect the other issues litigated by the parties at the hearing. The two-step DCF methodology uses the same IBES short-term growth projections as the one-step DCF methodology, and the same raw data is used to calculate dividend yields under both methodologies. In addition, the issues of using a national vs. a regional proxy group, application of credit screens, exclusion of companies with dividend cuts or merger activity within the six-month study period, exclusion of outliers, and the placement of the base ROE within the zone of reasonableness are unaffected by what DCF methodology is used. We conclude that the Commission need not establish hearing procedures on the placement of the base ROE within the zone of reasonableness because the hearing already held before the Presiding Judge provided the parties a full opportunity to present evidence on all these issues, including a full opportunity to contest all the evidence we have relied upon in our findings concerning placement in the zone.[308] Accordingly, in order to resolve this proceeding as expeditiously and efficiently as possible consistent with due process, we will not reopen the record for the purpose of allowing any additional evidence to be presented on those issues. For the same reasons, we will not allow any further updating of the financial data beyond the October 2012 through March 2013 period approved in this order.

---

[308] *See, e.g.*, Ex. NET-300 at 7-8, 44-45, 45-72, 81-82; Ex. NET-400 at 26-27; Ex. S-12; Ex. NET-500 at 12.

156. Initial briefs are due within 45 days of the issuance of this order, and reply briefs are due within 30 days after the submission of initial briefs. The page limit for each brief will be 25 pages;[309] however, we impose no page limit on attached expert testimony.

VII. Elimination of the Treasury Bond Update

157. The Commission's policy in public utility ROE cases has been to establish a just and reasonable ROE, within a zone of reasonableness, based upon test-period evidence. However, because capital market conditions can change between the date the utility files its case-in-chief and the date the Commission issues a final decision, the Commission updates the ROE within the zone of reasonableness at the time of the final decision to reflect those capital market changes.[310] The Commission's long-standing practice has been to base this post-hearing adjustment on the change in U.S. Treasury bond yields during the same time period.[311] We now change that practice.

158. The premise underlying the use of U.S. Treasury bonds for the post-hearing ROE adjustment is that changes in ROE over time track changes in U.S. Treasury bond yields. However, while U.S. Treasury bond yields are an important indicator of capital market conditions and therefore inform our determination of an appropriate base ROE, the capital market conditions since the 2008 market collapse and the record in this proceeding have shown that there is not a direct correlation between changes in U.S. Treasury bond yields and changes in ROE. Therefore, the premise underlying the Commission's use of U.S. Treasury bond yields for post-hearing ROE adjustments is not always accurate. In *Southern California Edison Company*, a 2008 case in which the post-hearing adjustment was at issue, expert testimony indicated that, as U.S. Treasury bond yields decreased DCF results instead went up, indicating an inverse relationship between

[309] We take this opportunity to remind the participants of the requirements contained in Rule 2003 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2003 (2013).

[310] *E.g., S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 100 (citing *City of Vernon, Cal.*, Opinion No. 479, 111 FERC ¶ 61,092 (2005); *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC ¶ 61,001).

[311] *E.g., Ill. Power Co.*, 15 FERC ¶ 61,050, at 61,095 (1981); *see also Union Elec. Co. v. FERC*, 890 F.2d 1193 (D.C. Cir. 1989) (affirming the Commission's use of U.S. Treasury bond yields to make post-hearing adjustments within the range of reasonableness).

U.S. Treasury bond yields and utility ROE.[312] The record in this proceeding also shows an inverse relationship, but with rates moving in opposite directions: U.S. Treasury bond yields have increased while DCF results for the NETOs have gone down.[313]

159. The record in this proceeding also casts doubt on the magnitude, not just the direction, of the relationship between U.S. Treasury bond yields and utility ROE. The Commission's practice traditionally has been to adjust the ROE using a 1:1 correspondence between the ROE and the change in U.S. Treasury bond yields—i.e., for every basis point change in the U.S. Treasury bond yield the Commission would adjust the ROE by one basis point. However, the record in this proceeding indicates that the 1:1 correspondence may not be accurate under current financial conditions, and that a significantly different ratio might be more appropriate—i.e., for every basis point the U.S. Treasury bond yields change, the Commission should adjust the ROE by a fraction of that amount.[314] Thus, the record evidence indicates that, currently, adjusting ROEs based on changes in U.S. Treasury bond yields may not produce a rational result, as both the magnitude and direction of the correlation may be inaccurate.

160. Upon consideration of the record evidence in this proceeding, and in light of the economic conditions since the 2008 market collapse more generally, U.S. Treasury bond yields do not provide a reliable and consistent metric for tracking changes in ROE after the close of the record in a case. Accordingly, we conclude that, rather than updating ROEs by taking official notice of post-hearing changes in U. S. Treasury bond yields, a more reasonable approach is to allow the participants in a rate case to present the most recent financial data available at the time of the hearing, including post-test period financial data then available. This approach will ensure that all participants have an opportunity to present evidence and argument concerning the financial data used to determine the public utility's ROE, while allowing the ROE to be based on the most recent financial data available at the time of the hearing consistent with the due process

[312] *S. Cal. Edison Co. v. FERC*, 717 F.3d at 187-88 (remanding for the Commission to consider evidence that the U.S. Treasury bond yields and corporate bond yields might be inversely related and, therefore, not rationally related).

[313] *Compare* Initial Decision, 144 FERC ¶ 63,012 at P 551 n.49 (stating that the NETOs' DCF analyses in this proceeding indicate a lower cost of equity estimate for the prospective period than the refund period); *with* Ex. EMC-1 at 6-7 (indicating that the average 10-year U.S. Treasury bond yield in Oct. 2012 was between 1.7 and 1.8 percent) and Tr. 560 (indicating that the average 10-year U.S. Treasury bond yield for the period from Oct. 2012 to Mar. 2013 increased slightly to 1.83 percent).

[314] *See generally* May 8, 2013 Transcript at 562-570, 597, 605-606.

rights of the participants. This approach is also consistent with our longstanding practice in natural gas and oil pipeline rate cases.[315] We will, therefore, no longer use changes in U.S. Treasury bond yields to conduct post-hearing adjustments in public utility ROE proceedings.

VIII. Impact of the DCF Methodology Change on Existing ROE Transmission Incentive Adders

161. As noted above, the Commission is changing its approach to require that cost of equity estimates be calculated using the two-step DCF methodology. In general, the two-step DCF methodology will produce a narrower zone of reasonableness than use of the one-step DCF methodology for two reasons: (1) long-term growth rates are more stable than short-term growth rates, and (2) the two-step DCF methodology does not calculate a high-end estimate and low-end estimate for each proxy group company's cost of equity, but rather calculates one estimate for each company.

162. In section 219(a) of the FPA, Congress directed the Commission to establish incentive-based rate treatments to foster investment in transmission facilities. The Commission implemented FPA section 219 in Order No. 679.[316]

163. In order to satisfy the requirement of FPA section 219(d) that any rate incentives be consistent with FPA section 205, the Commission in Order No. 679 stated, "an incentive rate of return sought by an applicant must be within a range of reasonable returns and the rate proposal as a whole must be within the zone of reasonableness before it will be approved."[317]

164. Based on the Commission's policy that the total ROE including any incentive ROE is limited to the zone of reasonableness, the Commission has found in the past that an incentive ROE may not be implemented in full by the utility if the total ROE exceeds the zone of reasonableness. In *Pacific Gas and Electric Company*, for example, the Commission stated that a 200 point basis adder previously granted to Pacific Gas & Electric Company would be limited to within the range of the zone of reasonableness

[315] Opinion No. 510, 134 FERC ¶ 61,129 at PP 242-246, *order on reh'g*, 142 FERC ¶ 61,198 at PP 205-206.

[316] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[317] *Id*. P 2; *see also id.* P 93.

determined at hearing.[318] The Commission has consistently applied this policy in other recent incentive ROE cases.[319] Nothing in this order changes this Commission policy.

165. Accordingly, when a public utility's ROE is changed, either under section 205 or section 206 of the FPA, that utility's total ROE, inclusive of transmission incentive ROE adders, should not exceed the top of the zone of reasonableness produced by the two-step DCF methodology.

IX. Conclusion

166. On balance, we find that our actions in this order, including the shift to the use of the two-step DCF methodology, the placement of the NETOs' base ROE at the midpoint of the upper half of the zone of reasonableness, and the elimination of the post-hearing adjustment based on U.S. Treasury bonds, taken together produce a base ROE that reasonably balances investor and consumer interests consistent with *Hope* and *Bluefield* and allow just and reasonable rates for consumers and transmission owners.[320]

The Commission orders:

(A) The Initial Decision is hereby affirmed in part and reversed in part, as described in the body of this order.

---

[318] *Pac. Gas & Elec. Co.*, 141 FERC ¶ 61,168, at P 26 (2012) ("While we continue to grant the 200 basis-point adder for the Path 15 upgrade, we remind PG&E that any ROE adder is limited to within the range of reasonableness of the ROE . . . ").

[319] *See Trans Bay Cable, LLC*, 145 FERC ¶ 61,151, at PP 18-19 (2013); *Atl. Path 15, LLC*, 135 FERC ¶ 61,037 (2011).

[320] *See, e.g.*, *Hope*, 320 U.S. at 603.

(B) A paper hearing is hereby established, as discussed in the body of this order. Initial briefs are due within 45 days of the issuance of this order, and reply briefs are due within 30 days after the submission of initial briefs. Briefs are limited to 25 pages.

By the Commission. Commissioner Norris is dissenting in part with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix

EL11-66-000: MARTHA COAKLEY, ET.AL. V. BANGOR HYDRO-ELECTRIC CO., ET.AL.
FERC DCF Analysis: Natural Gas Model Using Data for the Six-Month Period Beginning October 2012 and Ending March 2013
Data Screens: Value Line data & I/B/E/S growth; Pays common dividend; No merger activity in past 6 months
Risk Screens: Credit Ratings (S&P: A to BBB-, Moody's A1 to Baa3)

		6 Mos. Avg	Growth Rate ("g")			Adj. Div.	DCF	
Ticker	Company Name	Div. Yield	I/B/E/S	GDP	Composite	Yield	Result	Reason for Removal
ALE	ALLETE, Inc.	4.37%	6.00%	4.39%	5.46%	4.49%	9.95%	
LNT	Alliant Energy Corp.	4.14%	5.87%	4.39%	5.38%	4.25%	9.63%	
AEE	Ameren Corp.	4.99%	-1.80%	4.39%	0.26%	4.99%	--	Low-end Outlier
AEP	American Electric Power Co., Inc.	4.22%	3.60%	4.39%	3.86%	4.31%	8.17%	
AVA	Avista Corp.	4.84%	4.00%	4.39%	4.13%	4.94%	9.07%	
BKH	Black Hills Corp.	4.00%	6.00%	4.39%	5.46%	4.11%	9.57%	
CNP	CenterPoint Energy, Inc.	3.99%	5.00%	4.39%	4.80%	4.09%	8.89%	
CNL	Cleco Corp.	3.20%	8.00%	4.39%	6.80%	3.30%	10.10%	
CMS	CMS Energy Corp.	4.09%	5.90%	4.39%	5.40%	4.20%	9.60%	
ED	Consolidated Edison, Inc.	4.26%	2.00%	4.39%	2.80%	4.32%	7.12%	
D	Dominion Resources, Inc.	4.22%	7.27%	4.39%	6.31%	4.36%	10.67%	
DTE	DTE Energy Co.	3.97%	4.42%	4.39%	4.41%	4.05%	8.46%	
DUK	Duke Energy Corp.	4.62%	4.20%	4.39%	4.26%	4.72%	8.98%	
EIX	Edison International	2.91%	-1.90%	4.39%	0.20%	2.91%	--	Low-end Outlier
EE	El Paso Electric Co.	3.04%	3.70%	4.39%	3.93%	3.10%	7.03%	
EDE	Empire District Electric Co.	4.73%	3.00%	4.39%	3.46%	4.81%	8.28%	
FE	FirstEnergy Corp.	5.26%	4.60%	4.39%	4.53%	5.38%	9.91%	
GXP	Great Plains Energy Inc.	4.04%	6.55%	4.39%	5.83%	4.16%	9.99%	
HE	Hawaiian Electric Industries, Inc.	4.75%	3.30%	4.39%	3.66%	4.83%	8.50%	
IDA	IDACORP, Inc.	3.39%	4.00%	4.39%	4.13%	3.46%	7.59%	
TEG	Integrys Energy Group, Inc.	5.01%	5.67%	4.39%	5.24%	5.15%	10.39%	
NEE	NextEra Energy, Inc.	3.72%	6.20%	4.39%	5.60%	3.82%	9.42%	
NU	Northeast Utilities	3.67%	8.04%	4.39%	6.82%	3.79%	10.62%	
NWE	NorthWestern Corp.	4.18%	5.00%	4.39%	4.80%	4.28%	9.08%	

OGE	OGE Energy Corp.	2.87%	4.55%	4.39%	4.50%	2.93%	7.43%	
OTTR	Otter Tail Corp.	4.60%	5.00%	4.39%	4.80%	4.71%	9.51%	
POM	Pepco Holdings, Inc.	5.46%	3.63%	4.39%	3.88%	5.57%	9.45%	
PCG	PG&E Corp.	4.34%	3.10%	4.39%	3.53%	4.41%	7.94%	
PNW	Pinnacle West Capital Corp.	4.10%	7.30%	4.39%	6.33%	4.23%	10.56%	
POR	Portland General Electric Co.	3.86%	5.58%	4.39%	5.18%	3.96%	9.14%	
PPL	PPL Corp.	4.96%	2.70%	4.39%	3.26%	5.04%	8.31%	
PEG	Public Service Enterprise Group Inc.	4.59%	-0.68%	4.39%	1.01%	4.61%	--	Low-end Outlier
SCG	SCANA Corp.	4.26%	4.43%	4.39%	4.42%	4.36%	8.77%	
SRE	Sempra Energy	3.50%	5.65%	4.39%	5.23%	3.59%	8.82%	
SO	Southern Company	4.40%	4.80%	4.39%	4.66%	4.50%	9.16%	
TE	TECO Energy, Inc.	5.09%	2.90%	4.39%	3.40%	5.18%	8.58%	
UIL	UIL Holdings Corp.	4.72%	8.10%	4.39%	6.86%	4.88%	11.74%	
VVC	Vectren Corp.	4.64%	5.00%	4.39%	4.80%	4.75%	9.55%	
WR	Westar Energy, Inc.	4.42%	6.50%	4.39%	5.80%	4.55%	10.34%	
WEC	Wisconsin Energy Corp.	3.51%	5.37%	4.39%	5.04%	3.60%	8.64%	
XEL	Xcel Energy, Inc.	3.90%	5.12%	4.39%	4.88%	3.99%	8.87%	
	Zone of Reasonableness					**7.03%**	**---**	**11.74%**
						Midpoint:	**9.39%**	
						75th Percentile:	**10.57%**	

Long-term U.S. Gross Domestic Product (GDP) Growth Estimates For the Fourth Quarter of 2012

Source	Year Beginning	Nominal GDP ($Billion)	Year Ending	Nominal GDP ($Billion)	Annual GDP Growth (%)
IHS Global Insight [1]	2017	$ 19,369	2043	$ 57,599	4.28%
EIA [2]	2017	$ 19,421	2040	$ 51,037	4.29%
SSA [3]	2017	$ 20,392	2067	$ 191,986	4.59%
Average:					**4.39%**

Notes

[1] IHS Global Insight: Long-Term Macro Forecast - Baseline (U.S. Economy 30-Year Focus, First Quarter (March 1, 2013), Table Summary 1(a), http://www.globalinsight.com/

2 Report: Annual Energy Outlook 2013 (Release date: April 2013): Table 20. Macroeconomic Indicators. Nominal GDP=(Real GDP)*(GDP Chain-Type Price index). http://www.eia.gov/forecasts/aeo/data.cfm?filter=macroeconomic#macroeconomic (Table 20)

3 Social Security Administration: The 2012 OASDI Trustees Report (April 25, 2012), Table VI.F4.-- OASDI and HI Annual and Summarized Income, Cost, and Balance as a Percentage of GDP, Calendar Years 2012-90, Intermediate Assumptions. Note: (GDP2067)=(GDP2065)*((GDP2070/GDP2065)^(2/5)) http://www.ssa.gov/oact/tr/2012/VI_F2_OASDHI_GDP.html#181864

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group

Docket No. EL11-66-001

v.

Bangor Hydro-Electric Co.; Central Maine Power Co.; New England Power Co. d/b/a National Grid; New Hampshire Transmission LLC d/b/a NextEra; NSTAR Electric and Gas Corp.; Northeast Utilities Service Co.; The United Illuminating Co.; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Co.; Vermont Transco, LLC

(Issued June 19, 2014)

NORRIS, Commissioner, *dissenting in part*

We act today to address the backlog of complaint cases filed before the Commission arguing that returns on equity (ROE) for a number of public utilities are too high, and thus the rates derived from such ROEs are no longer just and reasonable. These cases have sat for too long, and I thank Chairman LaFleur for her leadership in working to promptly address the complaints under her watch.

Today's order addresses the complaint filed against the New England transmission owners' ROE. It also serves to announce the Commission's new approach for making determinations on ROE complaints as well as any ROEs proposed under Federal Power Act (FPA) section 205. Based on the record in this proceeding, today's order finds that an upward adjustment from long-standing Commission policy to set the ROE at the central tendency of the zone of reasonableness is warranted. The order then adjusts the ROE to the midpoint of the upper half of the zone.

While I agree that an upward adjustment from the central tendency is warranted in this case, the decision to grant New England transmission owners an ROE at the midpoint of the upper half of the zone of reasonableness is unjustified, lacks reasoning to support it, and sets troubling precedent. I am concerned that this determination subjects consumers to unjust and unreasonable rates in this proceeding and potentially in future ROE proceedings.

Given unusual capital market conditions that all parties to this proceeding acknowledge, particularly the historically low bond yields, I support the Commission's decision to look beyond the results of our traditional discounted cash flow methodology to inform the placement of the ROE within the zone of reasonableness. The record in this proceeding shows that a straight-forward application of the discounted cash flow methodology would result in a dramatic decrease in ROE and result in a level below that generally set by state commissions for electric distribution assets. This level risks failing to meet our *Hope* and *Bluefield*[1] requirements that ROEs be set so as to enable transmission owners to attract capital for new investment in transmission. I strongly believe that as a nation we still need more investment in transmission to promote competitive markets, reduce congestion, enhance reliability, and enable access to renewable resources. For these reasons, I conclude in this proceeding that an upward adjustment from the central tendency is warranted.

However, I cannot support the upward adjustment from the central tendency approved in today's order. With little justification or support, today's order agrees to the New England transmission owners' request to set their ROE at the midpoint of the upper half of the zone of reasonableness. Today's order has not met the burden to show that a 118 basis point upward adjustment from the central tendency to the midpoint of the upper half of the zone is a necessary and appropriate measure in this proceeding to meet our *Hope* and *Bluefield* requirements, or our FPA section 205 and 206 mandate to ensure that rates are just and reasonable.

---

[1] *FPC v. Hope Natural Gas Co.*, 320 U.S. 581 (1944) (*Hope);* and *Bluefield Water Works & Improvement Co. V. Pub. Serv.* Comm'n, 262 U.S. 679 (1923) (*Bluefield).*

Indeed, today's order cites only two cases from over a decade ago where the Commission approved an ROE adjustment to the midpoint of the upper half.[2] These cases do not provide relevant precedent, because they involved adjusting the ROE above the central tendency based on the risk profile of a utility that differed from the proxy group studied, a determination that was not made in the current proceeding.[3]

Looking beyond today's order, my broader concern is that the precedent established through this adjustment could become the new norm that would potentially ratchet up and lock in substantially higher ROEs in future cases. I am further troubled by today's order in light of recent Commission decisions on Order No. 1000 compliance filings that have served to protect incumbent transmission owners from competition in the development of new transmission. Simply put, not only will incumbent transmission owners be more insulated from competition, they will also be the primary beneficiaries of the new precedent established in this proceeding that could provide for substantially higher ROEs.

Given the potential significance of today's decision, I would have set the appropriate level of the upward adjustment from the central tendency for paper hearing. The New England transmission owners convincingly argue in the record that an upward adjustment is warranted, but then with limited justification argue that the correct adjustment is the midpoint of the upper half of the zone of reasonableness. Meanwhile, consumer representatives and Commission trial staff at the hearing before the judge argue that no deviation from the central tendency is warranted, consistent with existing Commission policy. Parties were not on notice that the Commission would now deviate from its long-standing precedent that relies on the central tendency. A paper hearing would have efficiently afforded all affected parties the opportunity to make their case in the record as to the appropriate level of the upward adjustment from the central tendency. Regrettably, today's order tilts the balance in favor of the New England transmission owners without further recourse and fails to adequately give a voice to consumer interests.

[2] *Consumers Energy Co.*, 85 FERC ¶ 61,100 (1998); and *S. Cal. Edison Co.*, 88 FERC ¶ 61,254 (1999).

[3] Notably, moving from the central tendency to the midpoint of the upper half of the zone of reasonableness first in *Consumers Energy* and then in *S. Cal. Edison* resulted in an 18 basis point and a 58 basis point upward adjustment, respectively. In contrast, the adjustment in this case results in a much larger 118 basis point increase.

Finally, I note that in future ROE cases, if parties wish to argue for an upward adjustment, they should make their case for the appropriate level of the adjustment. The Commission should then determine whether or not the record evidence in each individual proceeding warrants an adjustment, and if so, to what level.

For these reasons, I respectfully dissent in part.

____

John R. Norris, Commissioner

165 FERC ¶ 61,030
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Kevin J. McIntyre, Chairman;
Cheryl A. LaFleur, and Neil Chatterjee.

Martha Coakley, Attorney General of the Commonwealth of Massachusetts	Docket Nos. EL11-66-001
Connecticut Public Utilities Regulatory Authority	EL11-66-004
Massachusetts Department of Public Utilities	EL11-66-005
New Hampshire Public Utilities Commission	
George Jepsen, Attorney General of the State of Connecticut	
Connecticut Office of Consumer Counsel	
Maine Office of the Public Advocate	
New Hampshire Office of the Consumer Advocate	
Rhode Island Division of Public Utilities and Carriers	
Vermont Department of Public Service	
Massachusetts Municipal Wholesale Electric Company	
Associated Industries of Massachusetts	
The Energy Consortium	
Power Options, Inc.	
Industrial Energy Consumer Group	

v.

Bangor Hydro-Electric Company
Central Maine Power Company
New England Power Company
New Hampshire Transmission LLC
Northeast Utilities Service Company, on behalf of its operating company affiliates: The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire
NSTAR Electric & Gas Corporation
The United Illuminating Company
Unitil Energy Systems, Inc.

Fitchburg Gas and Electric Light Company
Vermont Transco, LLC
ISO New England Inc.

ENE (Environment Northeast) Greater Boston Real Estate Board National Consumer Law Center NEPOOL Industrial Customer Coalition	Docket Nos. EL13-33-000 EL13-33-002

v.

Bangor Hydro-Electric Company
Central Maine Power Company
New England Power Company
New Hampshire Transmission LLC
NSTAR Electric Company
Northeast Utilities Service Company
The United Illuminating Company
Unitil Energy Systems, Inc.
Fitchburg Gas and Electric Light Company
Vermont Transco, LLC

Attorney General of the Commonwealth of Massachusetts	Docket No. EL14-86-000

Connecticut Public Utilities Regulatory Authority
Massachusetts Municipal Wholesale Electric Company
New Hampshire Electric Cooperative, Inc.
Massachusetts Department of Public Utilities
New Hampshire Public Utilities Commission
George Jepsen, Attorney General of the State of Connecticut
Connecticut Office of Consumer Counsel
Maine Office of the Public Advocate
New Hampshire Office of the Consumer Advocate
Rhode Island Division of Public Utilities and Carriers
Vermont Department of Public Service
Associated Industries of Massachusetts
The Energy Consortium
Power Options, Inc.
Western Massachusetts Industrial Group
Environment Northeast

National Consumer Law Center
Greater Boston Real Estate Board
Industrial Energy Consumer Group

v.

Bangor Hydro-Electric Company
Central Maine Power Company
New England Power Company
New Hampshire Transmission LLC
Northeast Utilities Service Company, on behalf of its operating company affiliates: The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire
NSTAR Electric Company
The United Illuminating Company
Unitil Energy Systems, Inc.
Fitchburg Gas and Electric Light Company
Vermont Transco, LLC

Belmont Municipal Light Department — Docket Nos. EL16-64-000, EL16-64-002
Braintree Electric Light Department
Concord Municipal Light Plant
Georgetown Municipal Light Department
Groveland Electric Light Department
Hingham Municipal Lighting Plant
Littleton Electric Light & Water Department
Middleborough Gas & Electric Department
Middleton Electric Light Department
Reading Municipal Light Department
Rowley Municipal Lighting Plant
Taunton Municipal Lighting Plant
Wellesley Municipal Light Plant

v.

Central Maine Power Company
Emera Maine (formerly known as Bangor Hydro-Electric Company)
Eversource Energy Service Company and its operating company affiliates: The Connecticut Light and Power Company, Western Massachusetts

Electric Company, Public Service Company of
New Hampshire, and NSTAR Electric Company
New England Power Company
New Hampshire Transmission LLC
The United Illuminating Company
Fitchburg Gas and Electric Light Company
Vermont Transco, LLC

ORDER DIRECTING BRIEFS

(Issued October 16, 2018)

1. In *Emera Maine v. FERC*,[1] the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated and remanded Opinion No. 531,[2] which addressed the New England Transmission Owners' (NETO) return on equity (ROE). The remand in that proceeding and three other proceedings involving NETOs' ROE are currently pending before the Commission. In this order, we propose a methodology for addressing the issues that were remanded to the Commission in *Emera Maine* and we establish a paper hearing on how this methodology should apply to the proceedings pending before the Commission involving NETOs' ROE.

[1] 854 F.3d 9 (D.C. Cir. 2017).

[2] *Coakley Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234 (2014), *order on paper hearing*, 149 FERC ¶ 61,032 (2014) (Opinion No. 531-A), *order on reh'g*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015).

I. Background

A. Opinion No. 531 *et seq.*

2. On September 30, 2011, a group of transmission customers[3] in New England (Customers) filed a complaint[4] (First Complaint) under section 206 of the Federal Power Act (FPA)[5] alleging that NETOs'[6] ROE was unjust and unreasonable. At the time of the First Complaint, NETOs had a base ROE of 11.14 percent and their total ROE—i.e., the base ROE plus any ROE adders approved by the Commission—was not permitted to exceed 13.5 percent. The Commission established NETOs' preexisting 11.14 percent base ROE in Opinion No. 489.[7] That ROE was based on a Discounted Cash Flow (DCF)

---

[3] Customers include the state utility commissions of Connecticut, Massachusetts, New Hampshire, and Rhode Island; the Attorneys General of the State of Connecticut and of the Commonwealth of Massachusetts; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; New Hampshire Office of Consumer Advocate; Massachusetts Municipal Wholesale Electric Utility Company; New Hampshire Electric Cooperative; Associated Industries of Massachusetts; and the Industrial Energy Consumer Group. After the complaint was filed a group of municipal utilities—the Eastern Massachusetts Consumer-Owned Systems (EMCOS)—intervened in support. The EMCOS are Belmont Municipal Light Department; Braintree Electric Light Department; Concord Municipal Light Plant; Georgetown Municipal Light Department; Groveland Electric Light Department; Hingham Municipal Lighting Plant; Littleton Electric Light & Water Department; Middleborough Gas & Electric Department; Middleton Electric Light Department; Reading Municipal Light Department; Rowley Municipal Lighting Plant; Taunton Municipal Lighting Plant; and Wellesley Municipal Light Plant.

[4] Docket No. EL11-66-000.

[5] 16 U.S.C. § 824e (2012).

[6] NETOs are Emera Maine (f/k/a Bangor Hydro Electric Company); Central Maine Power Company; Eversource Energy Service Company (f/k/a Northeast Utilities Service Company) on behalf of: The Connecticut Light and Power Company, NSTAR Electric Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire; New England Power Company d/b/a National Grid; New Hampshire Transmission LLC; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; and Vermont Transco LLC.

[7] *Bangor Hydro-Elec. Co.*, Opinion N0. 489, 117 FERC ¶ 61,129 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarification*, 124 FERC ¶ 61,136

analysis using financial data for the period July to December 2004, with an update based on the monthly yields of ten-year constant maturity U.S. Treasury bonds for the period March through August 2006.

3. On May 3, 2012, the Commission issued an order setting the First Complaint for hearing before an administrative law judge (ALJ) and establishing a refund effective date of October 1, 2011.[8] Following the hearing, the Commission issued Opinion No. 531. As an initial matter, the Commission adopted certain changes to its use of the DCF methodology for evaluating and setting the Commission-allowed ROE. In particular, the Commission elected to replace the "one-step" DCF methodology, which considers only short-term growth projections for a public utility, with a "two-step" DCF methodology that considers both short- and long-term growth projections.[9] Applying the two-step DCF methodology and using financial data from the period October 2012 through March 2013, the Commission tentatively adopted a zone of reasonableness of 7.03 percent to 11.74 percent, subject to additional briefing regarding the appropriate long-term growth rate.[10]

4. The Commission, however, departed from its typical practice of setting the just and reasonable ROE of a group of utilities at the midpoint of the zone of reasonableness. The Commission explained that evidence of "anomalous" capital market conditions, including "bond yields [that were] at historic lows," made the Commission "less confiden[t] that the midpoint of the zone of reasonableness . . . accurately reflects the [ROE] necessary to meet the *Hope* and *Bluefield* capital attraction standards."[11] The

(2008), *aff'd sub nom. Conn. Dep't of Pub. Util. Control v. FERC*, 593 F.3d 30 (D.C. Cir. 2010).

[8] *Coakley, Mass. Attorney Gen. v. Bangor Hydro-Electric Co.*, 139 FERC ¶ 61,090 (2012). "Under Section 206 of the Federal Power Act, if FERC finds that any 'rate, charge, or classification' is 'unjust, unreasonable, unduly discriminatory or preferential,' the Commission is authorized to 'order refunds of any amounts paid' for a fifteen-month period following the 'refund effective date.'" *Braintree Elec. Light Dep't v. FERC*, 667 F.3d 1284, 1291 (D.C. Cir. 2012) (quoting 16 U.S.C. § 824e)).

[9] Opinion No. 531, 147 FERC ¶ 61,234 at PP 8, 32-41.

[10] *Id.* PP 9-10.

[11] *Id.* PP 144-145 & n.285. "*Hope*" and "*Bluefield*" refer to a pair of Supreme Court cases that require the Commission "to set a rate of return commensurate with other enterprises of comparable risk and sufficient to assure that enough capital is attracted to the utility to enable it to meet the public's needs." *Boroughs of Ellwood City, Grove City, New Wilmington, Wampum, & Zelienople, Pa. v. FERC*, 731 F.2d 959, 967 (D.C. Cir.

Commission therefore looked to four alternative benchmark methodologies: Three financial models—a risk premium analysis (Risk Premium), a capital-asset pricing model analysis (CAPM), and an expected earnings analysis (Expected Earnings)—as well as a comparison with the ROEs approved by state public utility commissions.[12] In considering those methodologies, the Commission emphasized that it was not departing from its long-standing reliance on the DCF methodology, but rather relying on those methodologies only to "inform the just and reasonable placement of the ROE within the zone of reasonableness established . . . by the DCF methodology."[13]

5. Based on these alternative methodologies, the Commission determined that an ROE of 10.57 percent, the midpoint of the upper half of the zone of reasonableness produced by the DCF, would be just and reasonable. Because that figure differed from NETOs' existing 11.14 percent ROE, the Commission concluded that the existing base ROE had become unjust and unreasonable and it therefore set NETOs' base ROE at 10.57 percent, pending a paper hearing concerning the long-term growth projection to use in the DCF analysis. Following that hearing, in Opinion No. 531-A the Commission reaffirmed its conclusion that 10.57 percent was the just and reasonable ROE and that NETOs' existing ROE was unjust and unreasonable. In addition, the Commission explained that NETOs' total ROE—i.e., the base ROE plus any transmission incentive ROE adders—could not exceed 11.74 percent, the top of the zone of reasonableness.[14] The Commission required NETOs' to submit a compliance filing to implement their new ROEs effective October 16, 2014—the date of Opinion No. 531-A.

B. <u>Subsequent Complaints against NETOs' ROE</u>

6. Three additional complaints have been filed against NETOs' ROE. First, on December 27, 2012, a different group of transmission customers filed another complaint (Second Complaint) alleging that NETOs' ROE, which was at that point still 11.14 percent, was unjust and unreasonable.[15] On June 19, 2014—the same day that the

---

1984) (citing *FPC v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) (*Hope*) and *Bluefield Waterworks v. Pub. Serv. Comm'n of W.V.*, 262 U.S. 679 (1923) (*Bluefield*)).

[12] Opinion No. 531, 147 FERC ¶ 61,234 at PP 147-149.

[13] *Id.* P 146.

[14] Opinion No. 531-A, 149 FERC ¶ 61,032 at P 11.

[15] Docket No. EL13-33-000. The complainants in the Second Complaint are ENE (Environment Northeast), the Greater Boston Real Estate Board, the National Consumer Law Center, and the NEPOOL Industrial Customer Coalition. Several of the parties to the First Complaint subsequently intervened in the Second Complaint proceeding.

Commission issued Opinion No. 531—the Commission issued an order setting the Second Complaint for hearing before an ALJ and establishing a refund effective date of December 27, 2012.[16] Second, on July 31, 2014, Customers filed a third complaint (Third Complaint) once again contending that NETOs' 11.14 percent[17] base ROE was unjust and unreasonable.[18] On November 24, 2014, the Commission issued an order setting the Third Complaint for an ALJ hearing, consolidating the hearings on the Second Complaint and the Third Complaint, and establishing a refund effective date of July 31, 2014.[19]

7. On March 22, 2016, the ALJ issued an initial decision in the consolidated proceedings on the Second Complaint and the Third Complaint.[20] Regarding the Second Complaint, the ALJ adopted a zone of reasonableness of 7.12 percent to 10.42 percent based on financial data for the period September 2013 through February 2014.[21] The ALJ also determined that the anomalous market conditions identified in Opinion No. 531 persisted and, after considering the alternative benchmark methodologies, that the just and reasonable ROE was 9.59 percent—halfway between the midpoint and the upper

---

Although the parties to the Second Complaint differed from the First Complaint, we will continue to refer to them simply as "Customers" because those differences are not relevant for the purposes of this order.

[16] *ENE (Environment Northeast) v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,235, at P 1 (2014).

[17] Although Customers filed the Third Complaint after the Commission issued Opinion No. 531, the Commission had not yet issued Opinion No. 531-A, which set the effective date for NETOs' 10.57 percent base ROE, meaning that the 11.14 percent figure remained in effect.

[18] Docket No. EL14-86-000. The parties to the Third Complaint included, among others, the parties to the First and Second Complaints. Once again, we will refer to them simply as "Customers."

[19] *Attorney Gen. of the Commonwealth of Mass. v. Bangor Hydro-Elec. Co.*, 149 FERC ¶ 61,156, at P 1 (2016).

[20] *ENE (Environment Northeast) v. Bangor Hydro-Elec. Co.*, 154 FERC ¶ 63,024 (2016).

[21] *Id.* P 629.

bound of the zone of reasonableness.[22] Regarding the Third Complaint, the ALJ adopted a zone of reasonableness of 7.04 percent to 12.19 percent based on financial data for the period November 2014 through April 2015. After again finding the capital market conditions to be anomalous, the ALJ found that the alternative benchmark methodologies indicated that the just and reasonable ROE was 10.90 percent—halfway between the midpoint and the upper bound of the zone of reasonableness.[23] The parties to those proceedings have filed briefs on exception to the Commission, which has not yet issued an opinion on the ALJ's initial decision.

8. Finally, on April 29, 2016, Customers filed a fourth complaint (Fourth Complaint) contending that NETOs' base ROE, which had by then been reduced to 10.57 percent, was unjust and unreasonable.[24] On September 20, 2016, the Commission again set the complaint for hearing before an ALJ and also established a refund effective date of April 29, 2016.[25] At the hearing, the parties presented updated financial information for their proposed proxy companies for the period May through October 2017. On March 27, 2018, the ALJ issued an initial decision on the Fourth Complaint.[26] The ALJ found that NETOs' base ROE of 10.57 percent, which with incentive adders may reach a maximum ROE of 11.74 percent, was not unjust and unreasonable and therefore, that it was unnecessary to reach the issue of what would be a just and reasonable alternative base ROE.[27] The ALJ found that neither EMCOS nor Commission Trial Staff (Trial Staff) had met their burden of producing a properly specified DCF analysis because, among other things, they improperly excluded a certain entity from their proxy groups and excluded proxy companies for which the Institutional Brokers Estimate System (IBES) reported no data, but failed to include those companies in their updates after IBES reported the data later.[28] The ALJ found that, because of the defects and deficiencies in

---

[22] *Id.* PP 824-825.

[23] *Id.* PP 930, 937.

[24] Docket No. EL16-64-000. The Fourth Complaint was filed by EMCOS, whom we will again refer to simply as "Customers."

[25] *Belmont Mun. Light Dep't v. Cent. Maine Power Co.*, 156 FERC ¶ 61,198, at P 1 (2016).

[26] *Belmont Mun. Light Dep't v. Cent. Maine Power Co.*, 162 FERC ¶ 63,026 (2018).

[27] *Id.* PP 2-3.

[28] *See id.* PP 207-221.

the DCF analyses presented by EMCOS and Trial Staff, they had failed to meet their burden of proof under the first prong of *Emera Maine* to show that the existing ROE was unjust and unreasonable by means of a DCF analysis that they properly specified and applied to the facts of the case. The ALJ therefore found that it was unnecessary to reach the issue of whether the existing 10.57 percent base ROE fell within the statutory zone of just and reasonable rates envisioned by the FPA.[29] The ALJ also noted that it was unnecessary to delve further into the parties' evidence of "anomalous capital market conditions" and "alternative methodologies" to the DCF analyses because the EMCOS and Trial Staff, who had the burden of proof under the first prong, denied that "anomalous capital market conditions" existed and did not rely on that notion to satisfy their burden of proof under the first prong.[30]

C. ***Emera Maine***

9. Both NETOs and Customers petitioned for review of Opinion No. 531 *et seq.* before the D.C. Circuit. NETOs and Customers advanced several arguments, two of which are relevant here. First, NETOs argued that the Commission did not satisfy the first prong of the FPA section 206 inquiry because it did not adequately demonstrate that NETOs' existing 11.14 percent base ROE was unjust and unreasonable. NETOs argued that, because that 11.14 percent figure was within the zone of reasonableness produced by the DCF, the Commission erred in finding their existing ROE unjust and unreasonable. NETOs further argued that the Commission's approach of determining what a just and reasonable ROE would be using the data from the study period compiled by the ALJ and comparing that value to the existing base ROE was insufficient to show that their existing base ROE was unjust and unreasonable.

10. Second, Customers argued that the Commission did not satisfy the second prong of the FPA section 206 inquiry because the Commission had not adequately shown that the 10.57 percent base ROE that it set in Opinion No. 531 was just and reasonable. Customers argued that the Commission had not adequately shown that the anomalous capital markets and the alternative benchmark methodologies justified a base ROE above

---

[29] *Id.* P 227. As discussed in detail *infra*, the notion of a statutory zone of just and reasonable rates under the FPA is distinctly different from the zone of reasonableness produced by the Commission's DCF methodology and other financial models for estimating a company's cost of equity.

[30] *Id.* P 226.

the midpoint of the zone of reasonableness. They further argued that, in any case, the Commission had not demonstrated that 10.57 percent was an appropriate base ROE.[31]

11. In *Emera Maine*, the D.C. Circuit agreed with both NETOs and Customers and vacated and remanded Opinion No. 531 *et seq*. As an initial matter, the D.C. Circuit rejected NETOs' argument that an ROE within the DCF-produced zone of reasonableness could not be deemed unjust and unreasonable. The D.C. Circuit explained that the zone of reasonableness established by the DCF is not "coextensive" with the "statutory" zone of reasonableness envisioned by the FPA.[32] Accordingly, the D.C. Circuit concluded that the fact that NETOs' existing ROE fell within the zone of reasonableness produced by the DCF did not necessarily indicate that it was just and reasonable for the purposes of the FPA.[33]

12. Nevertheless, the D.C. Circuit agreed with NETOs that the Commission had not adequately shown that their existing ROE was unjust and unreasonable. The D.C. Circuit explained that the FPA's statutory "zone of reasonableness creates a broad range of potentially lawful ROEs rather than a single just and reasonable ROE" and that whether a particular ROE is unjust and unreasonable depends on the "particular circumstances of the case."[34] Thus, the fact that NETOs' existing ROE did not equal the just and reasonable ROE that the Commission would have set using the current DCF analysis inputs did not necessarily indicate that NETOs' existing ROE fell outside the statutory zone of reasonableness.[35] As such, the D.C. Circuit concluded that Opinion No. 531 "failed to include an actual finding as to the lawfulness of [NETOs'] existing base ROE"

---

[31] NETOs and Customers raised additional arguments regarding other conclusions that the Commission reached in Opinion No. 531. For example, the Customers contended that anomalous market conditions did not justify any adjustment of NETOs' ROE above the midpoint of the zone of reasonableness produced by the DCF analysis. The D.C. Circuit did not rely on these arguments as reasons for its decision vacating and remanding Opinion No. 531 and, for that reason, we need not summarize them further here.

[32] *Emera Maine*, 854 F.3d at 22-23.

[33] *Id.* at 23.

[34] *Id.* at 23, 26.

[35] *Id.* at 27 ("To satisfy its dual burden under section 206, FERC was required to do more than show that its single ROE analysis generated a new just and reasonable ROE and conclusively declare that, consequently, the existing ROE was per se unjust and unreasonable.").

and that its conclusion that their existing ROE was unjust and unreasonable was itself arbitrary and capricious.[36]

13. The D.C. Circuit also agreed with Customers that the Commission had not adequately shown that the 10.57 percent ROE that it set was just and reasonable. Although recognizing that the Commission has the authority "to make 'pragmatic adjustments' to a utility's ROE based on the 'particular circumstances' of a case," the D.C. Circuit nevertheless concluded that the Commission had not explained why setting the ROE at the upper midpoint was just and reasonable.[37] The D.C. Circuit noted, in particular, that the Commission relied on the alternative models and state-regulated ROEs to support a base ROE *above* the midpoint, but that it did not rely on that evidence to support an ROE *at* the upper midpoint.[38] In other words, the Court was concerned that the 10.57 percent ROE that the Commission identified as the just and reasonable rate was divorced from the numerical results of the alternative models.[39] Similarly, the D.C. Circuit noted that the Commission had concluded that a base ROE of 9.39 percent—the midpoint of the zone of reasonableness—might not be sufficient to satisfy *Hope* and *Bluefield* or to allow the utility to attract capital, but that the Commission had not similarly explained how a 10.57 percent base ROE was sufficient to meet either of those conditions. Because the D.C. Circuit found that the Commission had not pointed to record evidence supporting the specific point at which it set NETOs' ROE, the D.C. Circuit held that the Commission had not articulated the "rational connection" between the evidence and the rate that the FPA demands.[40]

14. Based on those two conclusions—that the Commission had not met its burden either under the first or the second prong of FPA section 206—the D.C. Circuit vacated and remanded Opinion No. 531 *et seq.*[41] Thus, the current state of affairs is this: There

[36] *Id.*

[37] *Id.* (quoting *FPC v. Nat. Gas Pipeline Co.*, 315 U.S. 575, 586 (1942)).

[38] *Id.* at 29 ("FERC's reasoning is unclear. On the one hand, it argued that the alternative analyses supported its decision to place the base ROE above the midpoint, but on the other hand, it stressed that none of these analyses were used to select the 10.57 percent base ROE.").

[39] *Id.* at 28 (faulting the Commission for failing to "establish a 'rational connection' between the record evidence and its decision.")

[40] *Id.* at 28-30.

[41] *Id.* at 30.

are four currently pending complaints against NETOs' ROE, all of which have been fully litigated before an ALJ. The D.C. Circuit vacated the Commission's determinations in its order on the First Complaint (i.e., Opinion No. 531), meaning that they are no longer precedential,[42] even though the Commission remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.[43] In the meantime, NETOs are continuing to collect their 10.57 percent base ROE, although the Commission has indicated that it will exercise its "broad remedial authority" to correct its legal error in order to make whatever ROE it sets on remand effective as of the date of Opinion No. 531-A.[44]

II. <u>Determination</u>

15. In this order, we describe how the Commission intends to address the issues that were remanded to the Commission in *Emera Maine*. In short, we intend to give equal weight to the results of the four financial models in the record, instead of primarily relying on the DCF model. In relying on a broader range of record evidence to estimate NETOs' cost of equity, we ensure that our chosen ROE is based on substantial evidence and bring our methodology into closer alignment with how investors inform their investment decisions.

16. We begin with the Commission's proposed framework for determining whether an existing ROE remains just and reasonable (i.e., the first prong of the FPA section 206 analysis). Specifically, we propose (1) relying on the three financial models that produce zones of reasonableness—the DCF, CAPM, and Expected Earnings models—to establish a composite zone of reasonableness; and (2) relying on that composite zone of reasonableness as an evidentiary tool to identify a range of presumptively just and reasonable ROEs for utilities with a similar risk profile to the targeted utility. Under this approach, we intend to dismiss an ROE complaint if the targeted utility's existing ROE falls within the range of presumptively just and reasonable ROEs for a utility of its risk profile—unless that presumption is sufficiently rebutted.

17. We then turn to the Commission's proposed framework for establishing a new just and reasonable ROE, where the existing ROE has been shown to be unjust and unreasonable (i.e., the second prong of the FPA section 206 analysis). At that stage, we propose to rely on all four financial models in the record—i.e., the three listed above,

---

[42] *ISO New England Inc.*, 161 FERC ¶ 61,031, at P 28 (2017).

[43] *Emera Maine*, 854 F.3d at 30.

[44] *ISO New England Inc.*, 161 FERC ¶ 61,031 at PP 24, 34.

plus the Risk Premium model[45]—to produce four separate cost of equity estimates. We propose to then give them equal weight by averaging the four estimates to produce the just and reasonable ROE. For each of the DCF, CAPM, and Expected Earnings models, we propose to use the central tendency of the respective zones of reasonableness as the cost of equity estimate for average risk utilities.[46] We would then average those three midpoint/median figures with the sole numerical figure produced by the Risk Premium model to determine the ROE of average risk utilities. We would use the midpoint/medians of the resulting lower and upper halves of the zone of reasonableness to determine ROEs for below or above average risk utilities, respectively. Because our current policy is to cap a utility's total ROE, *i.e.*, its base ROE plus incentive ROE adders, at the top of the zone of reasonableness, we propose to use the composite zone of reasonableness produced by the DCF, CAPM, and Expected Earnings to establish the cap on a utility's total ROE.

18. After explaining our proposed frameworks for the first and second prongs of our FPA section 206 analysis, we then perform an illustrative calculation using record evidence from the First Complaint proceeding. That calculation indicates that, for the time period at issue in the First Complaint, (1) the range of presumptively just and reasonable ROEs for NETOs is 9.60 percent to 10.99 percent; (2) NETOs' preexisting ROE of 11.14 is therefore unjust and unreasonable; (3) the just and reasonable ROE is 10.41 percent; and (4) the cap on NETOs' total ROE is 13.08 percent. However, these findings are merely preliminary. We conclude by establishing a paper hearing on how our proposed frameworks should apply to the four proceedings involving NETOs' ROE.

---

[45] Unlike the DCF, CAPM, and Expected Earnings models, the output of the Risk Premium model is a numerical point and therefore, it does not produce a range which can be used to determine a zone of reasonableness. Accordingly, we propose to use the Risk Premium model output in the second prong of the FPA section 206 analysis where we determine a specific just and reasonable ROE, but not in the first prong of the analysis, which requires models that produce a range that can be used to determine a zone of reasonableness.

[46] The Commission will continue to use the midpoint of the zone of reasonableness as the appropriate measure of central tendency for a diverse group of average risk utilities and the median as the measure of central tendency for a single utility. *See S. Cal. Edison Co.*, 131 FERC ¶ 61,020, at P 91 (2010), *remanded on other grounds sub nom. S. Cal. Edison Co. v. FERC*, 717 F.3d 177, 183-87 (D.C. Cir. 2013).

A. Determining Whether an Existing ROE has Become Unjust and Unreasonable

19. In this section we outline a new approach for determining whether an existing ROE remains just and reasonable. That new approach reflects the Commission's proposed policy for addressing this issue in the future, including in the proceedings currently pending before the Commission. Before outlining that approach, however, we review the guidance that the D.C. Circuit has provided regarding this task.

1. Background

20. The D.C. Circuit has explained that, to satisfy the first prong of an FPA section 206 inquiry into an ROE, the Commission must "make an explicit finding that [an] existing [ROE is] unjust and unreasonable before proceeding to set a new rate."[47] Although *Emera Maine* held that a difference between the existing ROE and the just and reasonable ROE that the Commission would set under current circumstances is, by itself, insufficient to show that the existing ROE is unjust and unreasonable, the D.C. Circuit has also held that a comparison between the existing ROE and the just and reasonable ROE that the Commission would establish under current circumstances is relevant—and, in some cases, determinative—for whether the existing ROE remains just and reasonable.[48] In addition, the D.C. Circuit has explained that, although showing that an existing ROE is entirely outside a zone of reasonableness produced by a financial model, such as the DCF methodology, is one way of demonstrating that an existing ROE is unjust and unreasonable, it is not the *only* way in which FERC can satisfy its burden under the first prong of FPA section 206.[49] The Commission may also find that an existing ROE—even one that is within the zone of reasonableness produced by its

[47] *Emera Maine*, 854 F.3d at 24.

[48] *Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 957 (D.C. Cir. 1983) (concluding that the difference between the existing ROE and the just and reasonable ROE that the Commission would have set was sufficient *as a matter of law* to show the existing rate was unjust and unreasonable); *see also Emera Maine*, 854 F.3d at 26 (explaining that the Commission's "finding that 10.57 percent was a just and reasonable ROE, *standing alone*, 'did not amount to a finding that every other rate of return was not'" (citing *Papago*, 723 F.2d at 957) (emphasis added)).

[49] *Emera Maine*, 854 F.3d at 24; *see also Pub. Serv. Comm'n of State of N.Y. v. FERC*, 642 F.2d 1335, 1350 n.27 (D.C. Cir. 1980) (finding that the fact that an existing ROE was outside the zone of reasonableness was sufficient to carry the Commission's burden to show that an existing rate was unjust and unreasonable under the analogous section 5 of the Natural Gas Act).

financial analysis—is unjust and unreasonable based on the "particular circumstances" of the case.[50]

21. The D.C. Circuit has not discussed in detail what "particular circumstances" are relevant to that determination in the context of an FPA section 206 proceeding. Nevertheless, it has, in the context of an FPA section 205 proceeding, noted factors that may be relevant to determining whether an ROE is just and reasonable.[51] Chief among those factors is the company's risk profile, with a riskier profile indicating that a higher ROE may be appropriate.[52] As the Supreme Court explained in *Hope*, when describing what has become the standard for evaluating whether an ROE is just and reasonable under the FPA, a utility's ROE "should be commensurate with returns on investments in other enterprises *having corresponding risks*."[53] Indeed, the D.C. Circuit has explained that failing to consider a utility's risk profile, at least relative to the proxy group companies, can itself be arbitrary and capricious.[54] In addition, the D.C. Circuit has

[50] *Emera Maine*, 854 F.3d at 23, 26.

[51] *See, e.g.*, *NEPCO Mun. Rate Comm. v. FERC*, 668 F.2d 1327, 1344 (D.C. Cir. 1981) (observing in the context of a challenge to the Commission approval of an FPA section 205 filing, which, among other things, established an ROE, that "[r]atemaking is a complicated process involving many factors, e.g., money market conditions, financial health of the utility, and financial risks.").

[52] *Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695, 700 (D.C. Cir. 2007); *Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289, 295 (D.C. Cir. 2001) (noting that, after establishing a proxy group, the Commission "then determin[es] where [the filing entity] belong[s] within that group, in large part on the basis of . . . business risk"); *Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54, 57 (D.C. Cir. 1999) ("Once the Commission has defined a zone of reasonableness . . . , it then assigns . . . a rate within that range to reflect specific investment risks . . . as compared to the proxy group companies."); *see also Emera Maine*, 854 F.3d at 29-30 (discussing instances in which the Commission had awarded a higher ROE because "the utility at issue was riskier than the proxy group.").

[53] *Hope*, 320 U.S. 591 at 603 (emphasis added); *Petal Gas*, 496 F.3d at 698 (discussing this standard in the context of whether rates are just and reasonable).

[54] *Petal Gas*, 496 F.3d at 700.

noted that financial considerations, such as the state of the capital markets, the financial condition of the utility in question, and other "financial risks" may also be relevant.[55]

2. Proposed Approach

22. We now propose to adopt a new framework for evaluating whether an existing ROE remains just and reasonable for purposes of the first prong of FPA section 206. In sum, we propose to establish a range of presumptively just and reasonable ROEs, within the zone of reasonableness indicated by the record evidence. As explained below, this framework reflects the D.C. Circuit's guidance, both in *Emera Maine* as well as in the D.C. Circuit's other decisions regarding the determination of a just and reasonable ROE.

23. The Commission has long relied on a financial model to guide its evaluation of whether an ROE is just and reasonable.[56] As explained below, we propose to continue using an analysis of the relevant financial considerations to establish an initial zone of reasonableness. However, as the D.C. Circuit observed in *Emera Maine*, even where the Commission's financial analysis produces an initial zone of reasonableness, the presence of that record evidence is not necessarily the end of the inquiry, and it is not a proxy for the just and reasonable standard in the FPA. Instead, the Commission may look to the particular circumstances of the case to determine whether an ROE—even one that falls within that zone—is just and reasonable for purposes of the first prong of FPA section 206.[57]

24. Consistent with the Commission's established practice and the D.C. Circuit's guidance, we continue to find that a utility's risk profile remains the "particular circumstance[]" most relevant to determining whether a point within a zone of reasonableness is a just and reasonable ROE for that utility. In particular, as noted, the courts have held that, to be just and reasonable, an ROE must be "commensurate"

---

[55] *See, e.g.*, *Aera Energy LLC v. FERC*, 789 F.3d 184, 194 (D.C. Cir. 2015) (observing that, in general, "'the higher the proportion of equity capital, the lower the financial risk . . . and thus, in this respect, the lower the necessary rate of return' on equity." (quoting *Missouri Pub. Serv. Comm'n v. FERC*, 215 F.3d 1, 2 (D.C. Cir. 2000))); *NEPCO*, 668 F.2d at 1344 (listing considerations for setting the ROE, including the health of the utility and its "financial risk.").

[56] *See generally Emera Maine*, 854 F.3d at 21 (explaining the Commission's approach to setting ROE); *Canadian Ass'n of Petroleum Producers v. FERC*, 308 F.3d 11, 15 (D.C. Cir. 2002) (similar); *Tenn. Gas Pipeline Co. v. FERC*, 926 F.2d 1206, 1209 (D.C. Cir. 1991) (similar).

[57] *Emera Maine*, 854 F.3d at 23, 27.

with the returns on investments in other enterprises having "corresponding risks." By the same token, an ROE—even one within the zone of reasonableness—that is *not* commensurate with the returns on investments in other enterprises having "corresponding risks" will not be just and reasonable. Accordingly, we conclude that a utility's relative risk profile should be the most critical consideration when identifying the "broad range of potentially lawful ROEs" that *Emera Maine* contemplates within the overall zone of reasonableness produced by the DCF when determining whether an existing ROE remains unjust and unreasonable.

25. The Commission historically has accounted for a utility's risk profile in two ways. First, it has attempted to compare that utility to other utilities facing similar risks by establishing a proxy group of comparable risk companies. Thus, for example, the Commission has limited the composition of the proxy group to utilities with a credit rating similar to that of the utility in question.[58] Second, recognizing that, nevertheless, the particular circumstances facing a utility may differ from some or all of the proxy group companies, the Commission has adjusted the ROE within the zone of reasonableness derived from the proxy group, increasing the ROE for a riskier utility and decreasing it for one that is less risky. Thus, as the D.C. Circuit explained in *Emera Maine*, the Commission has in multiple instances set a utility's ROE at the midpoint of the upper half of the zone reasonableness after finding "that the utility at issue was riskier than the proxy group, meaning that the utility's costs fell somewhere above the midpoint of the zone of reasonableness."[59] The D.C. Circuit has approved this approach, noting that, when dealing with a relatively risky utility, "the midpoint of the upper half [of the zone of reasonableness] was 'an obvious place to begin'" the analysis of what constitutes a just and reasonable ROE.[60] Similarly, the Commission has also held that, where a utility's risks are significantly less than those of the proxy group companies, an ROE at the relevant measure of central tendency for the lower half of the zone of reasonableness represents a just and reasonable ROE.[61]

26. Those longstanding determinations will form the basis of the Commission's approach to evaluating whether an existing ROE may be found unjust and unreasonable

---

[58] *See, e.g.*, Opinion No. 531, 147 FERC ¶ 61,234 at PP 106-108 (citing *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248, at 62,240 n.79 (2008)); *see also Petal Gas*, 496 F.3d at 699 ("[P]roxy group arrangements must be risk-appropriate . . . [t]hat principle is well-established.").

[59] *Emera Maine*, 854 F.3d at 29-30.

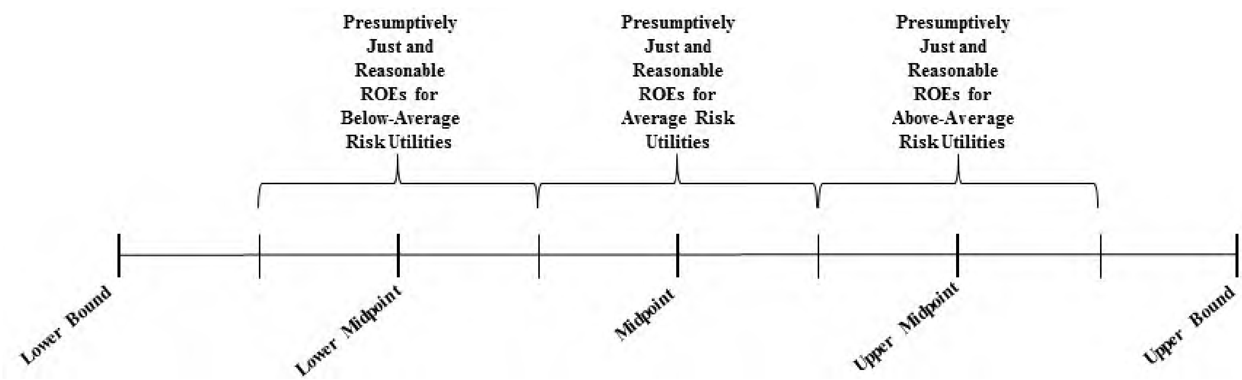
[60] *Id.* at 30 (quoting *Tenn. Gas*, 926 F.2d at 1213).

[61] *See Potomac-Appalachian Transmission Highline, LLC*, 158 FERC ¶ 61,050, at PP 270, 273 (2017).

under the first prong of FPA section 206. In particular, we conclude that the principal consideration for determining whether an existing ROE within the overall zone of reasonableness has become unjust and unreasonable is the risk profile of the utility or utilities for which the Commission is setting the ROE. This is consistent with the Commission's well-established policy on relative risk analysis, in which the presumptively just and reasonable ROE for an average-risk utility is the relevant measure of central tendency for the entire zone of reasonableness while the presumptively just and reasonable ROE for an above- or below-average risk utility is the relevant measure of central tendency for either the upper or lower half of the zone of reasonableness, respectively. Following that approach, logic dictates, and we conclude, that it typically would be unjust and unreasonable for an average-risk utility to receive an ROE that is closer to the ROE that would be just and reasonable for a utility of above- or below-average risk.

27. With these conclusions in mind, we find that, for an average risk utility, the "broad range of potentially lawful ROEs" that the D.C. Circuit contemplated in *Emera Maine* should correspond to those points that are closer to the ROE that the Commission would set for that utility than to the ROE for a utility of a different risk profile. As illustrated below in Figure 1, for a diverse group of average risk utilities, again such as NETOs, this range will constitute one quarter of the zone of reasonableness, centered on the midpoint. Every potential ROE within that range will be closer to the current just and reasonable ROE for an average-risk utility than the current just and reasonable ROE for a utility of a different risk profile.[62]

Figure 1: Zone of Reasonableness Quartiles



[62] In cases where the ROE of a single utility is at issue, the quartiles will be centered on the median of the overall zone of reasonableness for a single utility of average risk and the medians of the lower and upper halves of the zone of reasonableness for single utilities of below and above average risk respectively.

28. Pursuant to this framework, a finding that the existing ROE of an average risk utility falls within the applicable range of presumptively just and reasonable ROEs (in the case of an average risk utility, the middle quartile of the newly-calculated zone of reasonableness)[63] will support a holding that the existing ROE has not been shown to be unjust and unreasonable under the first prong of FPA section 206, at least absent additional evidence to the contrary. By the same token, a finding that the existing ROE of an average risk utility falls outside that range may support a holding that that the ROE has become unjust and unreasonable.

29. In evaluating whether an existing ROE has become unjust and unreasonable, the Commission may, in addition to applying the above framework, consider other indications of a change in capital market conditions since the existing ROE was established. For example, a significant decrease in financial indicators such as prime interest rates and U.S. Treasury and public utility bond yields, as well as changes in the returns on investments in other enterprises having corresponding risks, since the existing ROE was established may indicate that the existing ROE has become unjust and unreasonable. A utility's cost of equity is determined, at least in part, by comparison with other potential investments. As the return on those investments fluctuates, so too will the utility's cost of equity and, by extension, the ROE needed to service that cost of equity.

30. Lastly, it is important to explain how we intend to calculate the predicate, evidentiary zone of reasonableness that we will use to identify the range of presumptively just and reasonable ROEs. The Commission previously relied solely on the DCF model to produce the evidentiary zone of reasonableness. As explained below, we are concerned that relying on that methodology alone will not produce just and reasonable results. Therefore, we intend to expand the evidence on which we rely. Specifically, we intend to use the composite zone of reasonableness produced by the DCF, CAPM, and Expected Earnings models. Each of these three methodologies relies on a proxy group to determine a zone of reasonableness, and thus the top and bottom of the zone of reasonableness produced by each methodology can be averaged to determine a single composite zone of reasonableness. After determining the composite zone of reasonableness, we will then calculate the lower midpoint/median, midpoint/median, and upper midpoint/median of that zone. The presumptively just and reasonable ROEs for below-average-, average-, and above-average-risk utilities will then be the quartile of the zone corresponding to the lower midpoint/median, midpoint/median, and upper midpoint/median, respectively.

---

[63] Similarly, for a utility of above-average risk, the zone of presumptively just and reasonable ROEs is the quartile centered on the upper midpoint/median; for a utility of below-average risk, the zone of presumptively just and reasonable ROEs is the quartile centered on the lower midpoint/median.

31. As discussed below, because we are adopting a new approach to meeting the Commission's burden under the first prong of the FPA section 206 inquiry, we will institute a paper hearing on how our approach should apply to the records assembled in the four complaints against NETOs' ROE.

B. Determining a Just and Reasonable ROE

32. The Commission has relied upon the DCF methodology to determine a just and reasonable ROE for a public utility since the 1980s. However, as the D.C. Circuit has repeatedly observed, the Commission is not required to rely upon the DCF methodology alone or even at all.[64] For the reasons that follow, we find that, in light of current investor behavior and capital market conditions, relying on the DCF methodology alone will not produce a just and reasonable ROE. Instead, we propose to rely upon the results of all four financial models in the records for these proceedings: the DCF, CAPM, Expected Earnings, and Risk Premium models. We propose to give each of those four models equal weight, by calculating a single cost of equity estimate for each model and then averaging those four figures together to produce the just and reasonable ROE. To determine the cost of equity figure for average risk utilities using the DCF, CAPM, and Expected Earnings models, we propose to calculate the midpoint or median of the zone of reasonableness produced by each model, depending upon whether we are determining the ROE of a diverse group of utilities or a single utility. Those three midpoint/median figures would then be averaged with the single numerical figure produced by the Risk Premium model. We propose to use the midpoint/medians of the resulting lower and upper halves of the zone of reasonableness to determine ROEs for below or above average risk utilities, respectively.

1. Use of Multiple Financial Models

33. In *Hope*, the Supreme Court held that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial

---

[64] *Tenn. Gas*, 926 F.2d at 1211 (explaining that the Commission is free to reject the DCF methodology, provided it adequately explains its reasons for doing so); *Elec. Consumers Res. Council v. FERC*, 747 F.2d 1511, 1514 n.6 (D.C. Cir. 1984) ("neither statutes nor decisions of this court require that the Commission utilize a particular formula or a combination of formulae to determine whether rates are just and reasonable"); *NEPCO*, 668 F.2d at 1345 ("FERC is not bound 'to the service of any single formula or combination of formulas.'" (quoting *FPC v. Natural Gas Pipeline Co.*, 315 U.S. at 586)); *see also Emera Maine*, 854 F.3d at 27 (noting that the Commission has authority to make "'pragmatic adjustments' to a utility's ROE" based on the facts of the particular case (quoting *FPC v. Nat. Gas Pipeline Co.*, 315 U.S. at 586)).

integrity of the enterprise, so as to maintain its credit and to attract capital."[65] Thus, a key consideration in determining just and reasonable utility ROEs is determining what ROE a utility must offer in order to attract capital, i.e., induce investors to invest in the utility in light of its risk profile.[66] As the Commission stated in Opinion No. 414-B,[67] "the cost of common equity to a regulated enterprise depends upon what the market expects not upon precisely what is going to happen."[68] Thus, in determining what ROE to award a utility we must look to how investors analyze and compare their investment opportunities.

34. The record in these proceedings includes four traditional methods investors may use to estimate the expected return from an investment in a company. These are the DCF, CAPM, Expected Earnings, and Risk Premium methodologies.[69] The DCF analysis provides a market-based approach based upon market-determined dividend yields and expected dividend growth. The CAPM provides a market-based approach determined by beta, a measure of the risk based upon the volatility of a company's stock price over time in comparison to the overall market, and the risk premium between the risk-free rate (generally, long-term U.S. Treasury bonds) and the market's return (generally, the return of the S&P 500 or another broad indicator for common stocks). The Expected Earnings methodology provides an accounting-based approach that uses investment analyst estimates of return (net earnings) on book value (the equity portion of a company's overall capital, excluding long-term debt). Finally, the Risk Premium methodology is a market-oriented methodology based on the premium investors require above the return they expect to earn on a bond investment to reflect the greater risk of a stock investment. In *New Regulatory Finance*, a leading academic text, Roger Morin explains that none of these methods "conclusively determines or estimates the expected return for an individual firm. Each methodology possesses its own way of examining

[65] *Hope*, 320 U.S. at 603. *See also CAPP v. FERC*, 254 F.3d 289, 293 (D.C. Cir. 2001) ("In order to attract capital, a utility must offer a risk-adjusted expected rate of return sufficient to attract investors.").

[66] *See Bluefield*, 262 U.S. at 692-93 (discussing factors an investor considers in making investment decisions).

[67] *Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-B, 85 FERC ¶ 61,323 (1998).

[68] *Id.* at 62,268. *See also Kern River Gas Transmission Co.,* Opinion No. 486-B, 126 FERC ¶ 61,034, at P 120 (2008).

[69] *See, e.g.*, Roger A. Morin, *New Regulatory Finance* 428 (Public Utilities Reports, Inc. 2006) (Morin). These methods are described in the appendix to this order.

investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises that cannot be validated empirically."[70]

35. Investors have varying preferences as to which of these or other methods they may use to inform their investment decisions. As Morin states, "Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no monopoly as to which method is used by investors."[71] While some investors may give some weight to a DCF analysis, it is clear that other investors place greater weight on one or more of the other methods for estimating the expected returns from a utility investment, as well as taking other factors into account. Thus, cost of equity estimates based on all four of the methods described above are a reasonable measure of investor expectations, since they are among the information that investors rely upon when making investment decisions.[72]

36. In these circumstances, we believe that averaging the results of the three methods that produce zones of reasonableness—the DCF, CAPM, and Expected Earnings methodologies—will produce a composite zone of reasonableness that most accurately

---

[70] Morin at 429. *See also* Docket Nos. EL13-33-002 and EL14-86-000, Ex. CAP-1 at 7 ("Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions"); Docket Nos. EL13-33-002 and EL14-86-000, Ex. NET-1500 at 6 ("Different methodologies have been developed to estimate investors' expected and required return on capital, but all such methodologies are merely theoretical tools and generally produce a range of estimates based on different assumptions and inputs."); Docket No. EL16-64-002, Ex. EMC-1 at 46 ("No single model of investor expectations can capture, with perfect accuracy, all of the nuances that may affect investor decisions and expectations . . . The reason is that all models, by their nature, are simplifications of reality.").

[71] Morin at 429. *See also* Docket No. EL16-64-002, Ex. NET-2800 at 15 ("Investment bankers, investors, and corporate finance professionals use models and tools beside the DCF model.").

[72] We note that we will not consider the level of state ROEs when we are determining the composite zone of reasonableness, nor will we weight it equally with the financial models in establishing a new just and reasonable ROE. We will, however, consider evidence of state ROEs to the extent that the record adequately demonstrates that investors are using it to inform their investment decisions.

captures the cost of equity[73] that informs the ROE that the Commission must award to a utility so that the ROE can provide the return to investors necessary to satisfy their expectations. Additionally, the Risk Premium methodology should be included in the calculation of the average return of the composite zone of reasonableness for the same reason. Giving equal weight to all four of these methodologies in determining a utility's ROE is supported by Morin:

> In the absence of any hard evidence as to which method outdoes the other, all relevant evidence should be used and weighted equally, in order to minimize judgmental error, measurement error, and conceptual infirmities. A regulator should rely on the results of a variety of methods applied to a variety of comparable groups, and not on one particular method. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect explanation of that stock price.[74]

37. Record testimony also supports using multiple methodologies to determine a utility's ROE. For example, Dr. Jonathan A. Lesser testified on behalf of EMCOS that "I believe that the use of multiple reasonable methodologies is appropriate for two reasons: (i) the required cost of equity is inherently unobservable, and (ii) no single model designed to estimate those investor expectations is likely to be 100 percent accurate in reflecting investor expectations."[75] Similarly, John D. Quackenbush testified on behalf of NETOs that "The Commission should not limit itself to using only the DCF model or restrict itself when applying judgment to ROE model results. Since state regulatory commissions, corporate finance professionals, and investors use multiple methods and exercise judgment when estimating the cost of equity, it is perfectly reasonable for the Commission to rely on multiple models and exercise judgment when setting the base ROE in this proceeding."[76]

---

[73] A utility's cost of equity is the return that the utility must provide its shareholders in order to induce them to invest their capital in that utility. A utility's ROE is the return that the utility generates by using that invested capital in its operations.

[74] Morin at 429.

[75] Docket No. EL16-64-002, Ex. EMC-1 at 45.

[76] Docket No. EL16-64-002, Ex. NET-2500 at 15.

38. Moreover, any methodology has the potential for errors or inaccuracies. Therefore, relying exclusively on any single methodology increases the risk that the Commission could authorize an unjust and unreasonable ROE. For example, in discussing "model risk," Mr. Quackenbush explained that "[a]rbitrarily and mechanistically plugging data into a model, no matter how theoretically robust the model is, can result in outputs that do not reflect the real world."[77] There is significant evidence indicating that combining estimates from different models is more accurate than relying on a single model.[78] The Commission concludes that, by providing four different approaches to estimating the cost of equity and determining ROEs, using these models together reduces the risk associated with relying on only one model; that is, the risk of misidentifying the just and reasonable ROE by relying on a flawed cost of equity estimate.

39. In the briefs directed by this order, the participants may address whether there should be any adjustments in the manner these models were implemented in Opinion Nos. 531, 531-A, and 531-B. In those opinions, the Commission emphasized that it was

---

[77] *Id.* at 20-21. *See also* Morin at 428 ("Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data."); *id.* at 429-30 ("If a regulatory commission relies on a single cost of equity estimate or on a single methodology, that commission greatly limits its flexibility and increases the risk of authorizing unreasonable rates of return. The results from one methodology . . . are likely to contain a high degree of measurement error and may be distorted by short-term aberrations.").

[78] *See, e.g., In re. Connect Am. Fund*, 28 FCC Rcd. 7123, 7147 (2013) ("As the cost of equity reflects the uncertain expectations of investors, there is potential for introducing significant errors into the estimates, and no single model can be counted on exclusively to provide a precise estimate of the cost of equity."); *Use of a Multi-Stage Discounted Cash Flow Model in Determining the Railroad Industry's Cost of Capital*, STB Ex Parte No. 664 (Sub-No. 1), 2009 WL 197991, *11 (S.T.B. Jan. 23, 2009) ("As the Federal Reserve Board noted in its testimony in STB Ex Parte No. 664, academic studies had demonstrated that using multiple models will improve estimation techniques when each model provides new information. In addition, there is robust economic literature confirming that, in many cases, combining forecasts from different models is more accurate than relying on a single model.") (citations omitted); Docket Nos. EL13-33-002 and EL14-86-000, Tr. 675:10-14 (Avera) ("All we can do is use these imperfect models to try to get a handle on what the underlying reality is, and since each model has its own failings and assumptions, there is some safety in numbers by looking at more models.").

using the alternative methodologies only for the purpose of corroborating the decision to place the ROE above the midpoint of the zone of reasonableness,[79] and therefore the Commission explained that they were "sufficiently reliable—not to set the ROE itself—but rather to corroborate our decision."[80] The fact the Commission is now proposing to give equal weight to the alternative models along with the DCF methodology raises the issue whether there should be any adjustments in how we implement them.

2. Difficulties with Sole Reliance on the DCF Methodology

40. Our decision to rely on multiple methodologies in these four complaint proceedings is based on our conclusion that the DCF methodology may no longer singularly reflect how investors make their decisions. We believe that, since we adopted the DCF methodology as our sole method for determining utility ROEs in the 1980s, investors have increasingly used a diverse set of data sources and models to inform their investment decisions.[81] Investors appear to base their decisions on numerous data points and models, including the DCF, CAPM, Risk Premium, and Expected Earnings methodologies.[82] As demonstrated in Figure 2 below, which shows the ROE results

---

[79] *See, e.g.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at PP 103, 112, and 129.

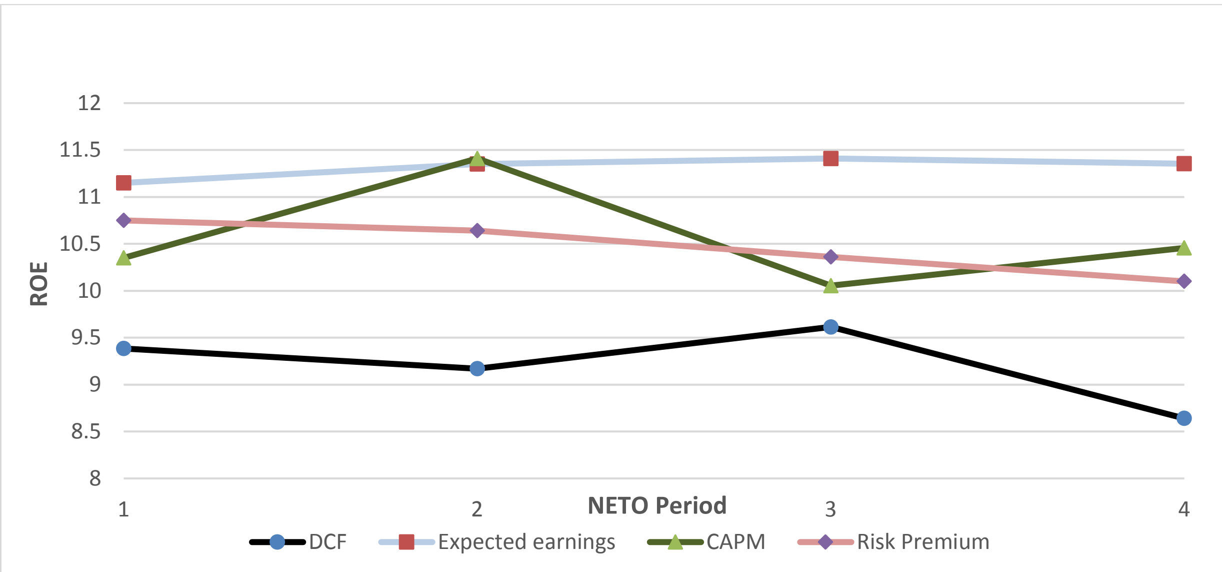
[80] *Id.* P 98.

[81] *See, e.g.*, Docket No. EL16-64-002, Ex. NET-02700 at 26:5-8 ("recognizing that there is no failsafe method to estimate investors' required cost of equity, approaches other than the DCF model have earned widespread acceptance with investment and finance professionals."); Tr. 474:2-6 (Quackenbush) ("I think it's always challenging to apply a financial model to a real world situation and come away feeling like you hundred percent got everything right. That's why analysts use ranges and why they use multiple models."); Docket No. EL11-66-001, Ex. NET-300 at 46 ("'Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.'") (quoting David C. Parcell, *The Cost of Capital – A Practitioner's Guide*, Society of Utility and Regulatory Financial Analysts (1997), Pt. 2 at 4)).

[82] *See, e.g.*, Docket No. EL11-66-001, Ex. NET-300 at 64-65 (explaining the prevalence of the CAPM) (citing Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins, *Best Practices in Estimating Cost of Capital: Survey and Synthesis*, Financial Practice and Education (Spring/Summer 1998)); Docket Nos. EL13-33-002 and EL14-86-000, Ex. NET-1300 at 27 (regarding common use of the risk premium approach); *id.* at 37-38 (discussing Value Line analyst projections of expected rates of return on common equity, the use of those projections in the expected earnings

from the four models over the four test periods at issue in this proceeding,[83] these models do not correlate such that the DCF methodology captures the other methodologies. In fact, in some instances, their cost of equity estimates may move in opposite directions over time. Although we recognize the greater administrative burden on parties and the Commission to evaluate multiple models, we believe that the DCF methodology alone no longer captures how investors view utility returns because investors do not rely on the DCF alone and the other methods used by investors do not necessarily produce the same results as the DCF. Consequently, it is appropriate for our analysis to consider a combination of the DCF, CAPM, Risk Premium, and Expected Earnings approaches.

Figure 2: ROE Results from ROE Models



41. During the periods used for the DCF analyses in these four complaint proceedings, capital market conditions differed significantly from those during the mid-1980s, when the Commission began relying exclusively on the DCF methodology to set ROEs, through the mid-2000s, when the Commission set NETOs' preexisting 11.14 percent ROE. For example, except for brief periods in 2002-2004, the 10-year U.S. Treasury

---

approach, and noting that "expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs.").

[83] The midpoints are used for the DCF, CAPM, and Expected Earnings analyses; however, the Risk Premium model does not produce a range from which to calculate a midpoint, so the actual Risk Premium output is the numerical point plotted for that model in the figure. This chart reflects the ROE models removing high-end and low-end outliers, as discussed below.

bond never fell below 4.00 percent during that entire period until January 2008, and its lowest rate was 3.33 percent in June 2003.

42. In contrast, the 10-year U.S. Treasury bond rates, beginning with the recession of 2008/2009 and continuing through the periods at issue in these proceedings, are the lowest since the early 1960s.[84] In December 2008, the 10-year U.S Treasury bond rate fell below 3.00 percent for the first time since June 1958.[85] During the six-month periods used for the DCF analyses in these four complaint proceedings, the 10-year U.S. Treasury bond rate was always below 3.00 percent. During the October 2012 to March 2013 period at issue in the First Complaint, the U.S. Treasury bond rate ranged from 1.65 to 1.98 percent.[86] During the September 2013 to February 2014 period at issue in the Second Complaint, the 10-year U.S. Treasury bond rate ranged from 2.62 to 2.90 percent.[87] During the November 2014 to April 2015 period at issue in the Third Complaint, the 10-year U.S. Treasury bond rate ranged from 1.88 to 2.33 percent.[88] During the May to October 2017 period at issue in the Fourth Complaint, the 10-year U.S. Treasury bond rate ranged from 2.25 to 2.40 percent.[89]

43. In Opinion Nos. 531 and 531-B, the Commission relied on the low 10-year U.S. Treasury bond yields during the October 2012 to March 2013 period to find that capital

---

[84] *See* Aswath Damodaran, *Equity Risk Premiums: Determinates, Estimation and Implications – The 2014 Edition* 81 (7th ed. 2014) (submitted as part of Workpapers of J. Randall Woolridge in Docket Nos. EL13-33-002 and EL14-86-000).

[85] *See* Docket Nos. EL13-33-002 and EL14-86-000, Exs. CAP-1 at 10 and CAP-4 at 1.

[86] During this six-month period, the average 10-year U.S. Treasury bond rate was 1.83 percent and the average 30-year U.S. Treasury bond rate was 2.85 percent. *See* Docket No. EL16-64-002, Table NET-17.

[87] During this six-month period, the average 10-year U.S. Treasury bond rate was 2.77 percent and the average 30-year U.S. Treasury bond rate was 3.77 percent. *See* Docket Nos. EL13-33-002 and EL14-86-000, Ex. NET-1500 at 15.

[88] During this six-month period, the average 10-year U.S. Treasury bond rate was 2.06 percent and the average 30-year U.S. Treasury bond rate was 2.69 percent. *See* Docket Nos. EL13-33-002 and EL14-86-000, Ex. NET-1712 at 123.

[89] During this six month period, the average 10-year U.S. Treasury bond rate was 2.26 percent and the average 30-year U.S. Treasury bond rate was 2.85 percent. *See* Docket No. EL16-64-002, Ex. NET-2900 at 12.

market conditions were "anomalous" during that period.[90] The Commission found that, in those circumstances, the Commission had "less confidence" that the midpoint of the zone of reasonableness determined by the DCF analysis satisfied the *Hope* and *Bluefield* capital attraction standards.[91] The Commission then considered the alternative cost of equity models to corroborate the Commission's determination to set NETOs' ROE "at a point above the midpoint" of the DCF analysis' zone of reasonableness, *i.e.*, the midpoint of the upper half of the zone.[92] However, the Commission emphasized that it was not departing from the use of the DCF methodology to determine the zone of reasonableness.[93] At the hearings on the Second, Third, and Fourth Complaints, the participants devoted a substantial portion of their evidentiary presentations to debating whether the continuing low-interest rate capital market conditions should be considered "anomalous" and whether those conditions distort the results of a DCF analysis.[94]

44. Those issues are largely irrelevant under the approach to determining just and reasonable ROEs that we are proposing in this order. Under this approach, we are averaging the cost of equity results produced by the DCF model and the other three models, using the midpoint/medians of the models that produce zones of reasonableness, to get one average figure for the cost of equity. We are not making an adjustment above the midpoint/median as we did in Opinion No. 531. There is thus no need to find that low-interest rate capital market conditions distort the results of a DCF analysis so as to justify adjusting the ROE for average risk utilities above the midpoint. To the contrary, our primary reason for proposing to average the results of a DCF analysis with the results of the CAPM, Expected Earnings, and Risk Premium analyses is that *investors use those models*, in addition to the DCF methodology, to inform their investment decisions. Under this approach, whether a change in the capital market conditions is anomalous or persistent is of less importance, because relying on multiple financial models makes it more likely that our decision will accurately reflect how investors are making their investment decisions. As discussed above, a key consideration in determining just and reasonable utility ROEs is determining what ROE a utility must offer in order to attract capital, *i.e.*, induce investors to invest in the utility in light of its risk profile. For this

---

[90] Opinion No. 531, 147 FERC ¶ 61,234 at P 145 n.285; Opinion No. 531-B, 150 FERC ¶ 61,165 at PP 49-50.

[91] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 49; Opinion No. 531, 147 FERC ¶ 61,234 at PP 146-149.

[92] Opinion No. 531, 147 FERC ¶ 61,234 at P 146.

[93] *Id.*

[94] *See, e.g.*, Docket No. EL16-64-002, Exs. NET-2200 at 28-39, NET-2800 at 9-31, EMC-1 at 79-97, EMC-28 at 8-20, and EMC-32 at 14-36.

purpose, we must look to the methods investors use to analyze and compare their investment opportunities in determining what ROE to award a utility consistent with the *Hope* and *Bluefield* capital attraction standards, and those methods include methods other than the DCF methodology.

45. We find further support for our proposed use of additional financial models in determining a utility's ROE based on our stated concerns that the DCF methodology alone may not capture how investors evaluate utility returns and identify a utility's relative risk profile. The underlying premise of the DCF methodology is that an investment in common stock is worth the value of the infinite stream of dividends discounted at a market rate commensurate with the investment's risk. Under this premise, increases in a company's actual earnings or projected growth in earnings would ordinarily be required to justify an increase in the company's stock price. Moreover, there is no evidence that investments in the utility sector have become less risky during these periods. However, it appears that during the periods at issue in these complaint proceedings, average utility stock prices have increased by more than would be justified by any increase in actual utility earnings or projected growth in earnings. From October 1, 2012 through December 1, 2017, the Dow Jones Utility Average increased from about 450 to 762.59, an increase of almost 70 percent.[95] However, utility earnings did not increase by nearly the same amount, as demonstrated in Figure 3 below, which shows the substantial increase in utilities' price to earnings (PE) ratio during the same period.[96] Moreover, average IBES three to five year growth projections appear not to have increased during that period.[97] Thus, there has not been an increase in either current or projected utility earnings that would justify the substantial increase in utility stock prices.

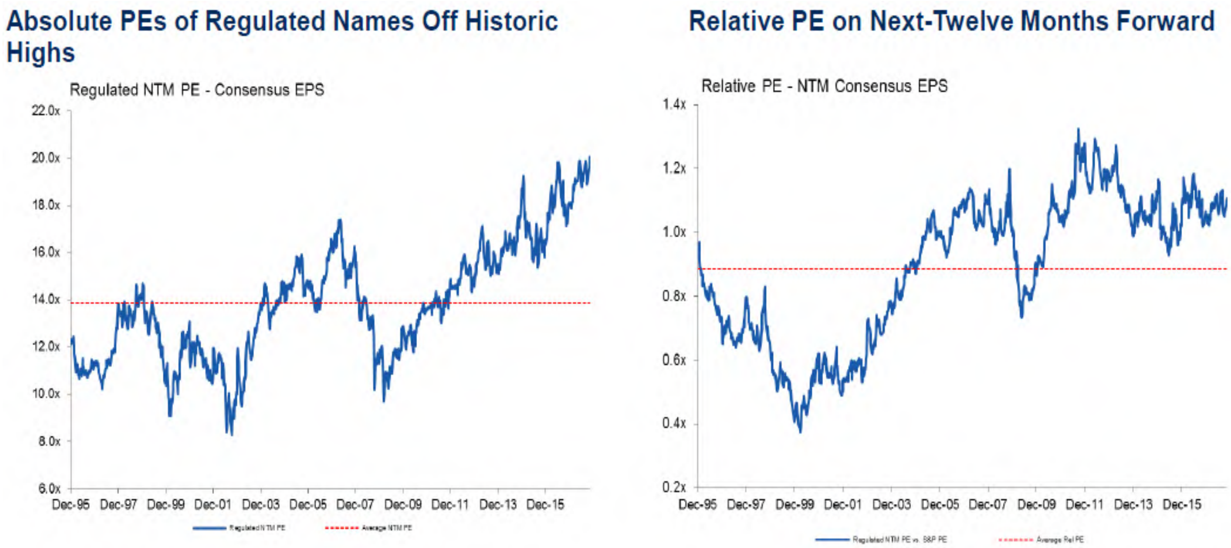
---

[95] *See* Docket No. EL16-64-002, Ex. CAP-65.

[96] *See* Figure 3, Evercore ISI chart, dated November 15, 2017, entitled "Absolute PEs of Regulated Names off Historic Highs." That chart shows a generally upward trend of price to equity ratios from 2008 through November 2017, with those ratios rising above their 14.0x historic average in 2011, and continuing to rise to close to 20.0x by November 2017. Moreover, the Relative Forward PE chart (vs. the S&P 500) has ranged from its all-time peak of approximately 1.25x in January 2015, well above its 20-year low of approximately 0.40x in late 1999 at the end of the dot.com bubble. Finally, the Relative PE chart demonstrates the relationship between utility and general market PEs has varied considerably over time. This extreme PE volatility is inconsistent with DCF theory.

[97] The average IBES three to five year growth projections for the four pending complaints, including any potential proxy group companies proposed by any party, are fairly similar at 5.05 percent, 5.28 percent, 5.44 percent, and 5.26 percent, respectively.

Figure 3: Regulated Utilities PE Chart



46. The fact that utility stock prices appear to have performed in a manner inconsistent with the theory underlying the DCF methodology during the periods at issue in these four complaint proceedings is an example of what NETOs have described as “model risk” — the risk that in some circumstances a model will produce results that do not reflect real world experience.[98] It appears that, for whatever the reason, investors during this period have seen greater value in utility stocks than the DCF methodology would predict. This suggests that the ROE estimated by that methodology may be correspondingly inaccurate.

47. We are also generally concerned with the low number of current IBES three to five-year earnings growth projections available for use in a two-step DCF analysis. The Commission has based the short-term growth projection in the two-step DCF analysis on IBES three to five year earnings growth projections, because those growth projections represent the consensus projection of a number of investment analysts.[99] For example,

[98] *See, e.g.*, Docket No. EL16-64-002, Ex. NET-2500 at 20; Docket Nos. EL13-33-002 and EL14-86-000, Ex. NET-1600 at 23 (“Like all valuation models, the DCF model is subject to ‘model risk’ . . . ‘Model risk’ is the risk that a model or algorithm used to predict values in real-world situations will fail to predict or represent the real phenomenon that is being modeled . . . there has been increasing recognition that the concept applies very broadly to models.”).

[99] Opinion No. 414-B, 85 FERC ¶ 61,323 at 62,268-9. *Northwest Pipeline Corp.* 87 FERC ¶ 61,266, at 62,058-9 (1999) (*Northwest*). *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048, at PP 75-76 (2008).

the Commission's 1999 decision in *Northwest* found that the IBES data "reflects an average of *numerous* projections of short-term growth of the proxy companies."[100] In that same decision, the Commission rejected the use of Value Line growth projections, because those projections are made by a single analyst.[101] Although IBES growth projections represented a consensus in the past, the record indicates that they do not reflect as robust a consensus, or perhaps any consensus, now. The majority of investment analysts that make and publish quarterly and annual earnings estimates no longer make and publish three-to-five year short-term projections of earnings growth. Indeed, the record in the Third Complaint proceeding indicates that in recent years the IBES data for many proxy companies have reflected only one to three analyst short-term growth projections.[102]

48. The reduced number of current IBES growth projections raises the question of whether the IBES growth rates reflect a consensus among investors. Further, the reduced number of short-term growth projections means that a significant change in a single analyst's growth projection for a particular proxy company can have a major effect on the DCF analysis result for that company. For example, the correction, described above in

---

[100] *Northwest*, 87 FERC at 62,059 (emphasis added).

[101] *Id*.

[102] Dr. J. Randall Woolridge explained that Reuters publishes the number of analysts contributing to each IBES short-term growth projection that it publishes and eliminates any analyst estimates that are more than six months old. *See* Docket Nos. EL13-33-002 and EL14-86-000, Ex. CAP-1 at 27-28. Dr. Woolridge's testimony included an exhibit showing the number of analysts providing short-term growth projections within the six months preceding November 30, 2014 for each of his 29 potential proxy companies. *See* Docket Nos. EL13-33-002 and EL14-86-000, Ex. CAP-6 at 4. The average number of analyst growth projections for each company was only slightly above two. There were three or fewer analyst growth projections for 23 of his 29 proxy companies, and only one proxy company for which there were more than four analyst growth projections. In addition, it appears that in some cases Thomson Reuters may extrapolate a percentage short-term growth projection from an analyst's estimates of the company's dollar earnings per share for different time periods, despite the fact the analyst did not actually make a percentage growth projection. *See* Docket Nos. EL13-33-002 and EL14-86-000, Ex. CAP-1 at 56. There is a risk that such extrapolations may be inaccurate. Dr. Woolridge provided an example involving Portland General Electric Company (Portland General), where an analyst's dollar earnings per share estimate for a past period reflected a one-time charge against earnings that would not properly be considered in projecting percentage growth in earnings for future periods. *See* Docket Nos. EL13-33-002 and EL14-86-000, Ex. CAP-11 at 2.

footnote 103, of the error in the growth projection of one of the four analysts reflected in the consensus growth projection for Portland General reduced the overall Reuters consensus projected short-term percentage growth in earnings for Portland General from 10.96 percent to 7.80 percent. Accordingly, the decreased number of short-term growth projections necessary to perform a DCF analysis of the proxy companies reduces our confidence in the results of that analysis and its suitability as the sole basis for our ROE determinations. However, because at least some investors continue to use the DCF model, we find it reasonable to give that model some weight, along with other models used by investors, in the overall approach to determining ROE proposed in this order.

3. Proxy Groups to be used for DCF, CAPM, and Expected Earnings Analyses

49. As described above, three of the four methodologies that we discussed above for determining the cost of equity use proxy groups to determine a range of reasonable returns. These include the DCF, CAPM, and Expected Earnings analyses. In selecting these proxy groups, the Commission intends to continue to use the same screens for developing a proxy group as the Commission has used in recent cases, including Opinion Nos. 531[103] and 551.[104] These screens are: (1) the use of a national group of companies considered electric utilities by Value Line;[105] (2) the inclusion of companies with credit ratings no more than one notch above or below the utility or utilities whose ROE is at issue;[106] (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut during the six month study period;[107] (4) the inclusion of companies with no merger activity during the six-month study period that is significant enough to distort the study inputs;[108] and (5) companies whose ROE results pass threshold tests of economic logic, including both a low-end outlier test and a high-end outlier test, as discussed below.

---

[103] 147 FERC ¶ 61,234 at P 97.

[104] 156 FERC ¶ 61,234 at P 20.

[105] Opinion No. 531, 147 FERC ¶ 61,234 at PP 96 and 100-102.

[106] The Commission requires use of both Standard and Poor's corporate credit ratings and Moody's issuer ratings when both are available. Opinion No. 531, 147 FERC ¶ 61,234 at P 107.

[107] *Id.* P 112.

[108] *Id.* P 114; Opinion No. 551, 156 FERC ¶ 61,234 at PP 37-43.

50. The first four screens listed above evaluate particular characteristics of the companies in question that do not vary depending upon the results of the DCF, CAPM, or Expected Earnings analyses. Accordingly, those screens may be used to develop a single group of proxy companies eligible for inclusion in the proxy group to be used for the purposes of DCF, CAPM, and Expected Earnings analyses, subject to the availability of data such as three-to-five year growth rates, betas, and earnings estimates, respectively. However, application of the last screen—whether the company's cost of equity estimate passes threshold tests of economic logic—depends upon the cost of equity estimate each of the three models produces. Thus, in determining the zone of reasonableness produced by each of these models, the low-end and high-end outlier tests must be applied separately to each model.

51. Under the low-end outlier test, the Commission excludes from the proxy group companies whose ROE fails to exceed the average 10-year bond yield by approximately 100 basis points, taking into account any natural break between the cost of equity estimates of the companies excluded from the proxy group and the lowest cost of equity estimate of the companies included in the proxy group.[109] The Commission excludes these low-end outliers on the ground that investors generally cannot be expected to purchase a common stock if debt, which has less risk than a common stock, yields essentially the same expected return.[110] The Commission will continue to use this test for purposes of the CAPM and Expected Earnings analyses as well as the DCF analysis.

52. The Commission found the high-end outlier issue to be moot in Opinion No. 531, because the two-step DCF methodology adopted in that case includes a projection of long-term growth for each company equal to GDP. As a result, no proxy company had a composite growth rate in excess of 7.66 percent or an ROE in excess of 11.74 percent. The Commission found that those percentages were well within any high-end outlier test the Commission had previously applied in utility rate cases.[111] However, neither the

[109] Opinion No. 531, 147 FERC ¶ 61,234 at P 123.

[110] *S. Cal. Edison Co.*, 92 FERC ¶ 61,070, at 61,266 (2000).

[111] Opinion No. 531, 147 FERC ¶ 61,234 at P 118.

CAPM nor Expected Earnings analyses include a long-term growth projection based on GDP that would normalize the ROEs produced by the model, similar to that used in the two-step DCF methodology. Moreover, the Commission recognizes that in unusual circumstances the two-step DCF methodology may produce unsustainably high results for a particular proxy company. Accordingly, given these facts and our decision to give the same weight to the CAPM and Expected Earnings analyses as to the DCF analysis, we find that a high-end outlier test should be applied to the results of each of these three methods.

53. The Commission proposes to treat as high-end outliers any proxy company whose cost of equity estimated under the model in question is more than 150 percent of the median result of all of the potential proxy group members in that model before any high or low-end outlier test is applied, subject to a "natural break" analysis similar to the approach the Commission uses for low-end DCF analysis results. This test should identify those companies whose cost of equity under the model in question is so far above the cost of equity of a typical proxy company as to suggest that it is the result of atypical circumstances not representative of the risk profile of a more normal utility.

54. To illustrate how this high-end outlier test would be applied, in the First Complaint, this test would exclude one company from the proxy group used for the Expected Earnings analysis. The median ROE under that methodology of all the companies eligible for inclusion in the proxy group after applying the first four screens described above is 10.2 percent. One hundred fifty percent of 10.2 percent is 15.3 percent. Dominion Resources Inc.'s (Dominion) cost of equity under the Expected Earnings analysis is 16.1 percent, and therefore this test would exclude Dominion in the determination of the Expected Earnings zone of reasonableness for the First Complaint. The next five highest Expected Earnings ROEs in that proceeding are 14.2 percent (Wisconsin Energy Corp.), 13.4 percent (CMS Energy Corp.), 12.9 percent (NextEra Energy, Inc.), 12.8 percent (Southern Company), and 12.3 percent (CenterPoint Energy, Inc.). Thus, there is a 190 basis point break between Wisconsin Energy Corp.'s 14.2 percent ROE and Dominion's 16.1 percent, which is over twice the next highest break of 80 basis points. In the First Complaint, this high-end outlier test does not eliminate any company from the proxy groups used in the DCF or CAPM analyses. The elimination of such outliers is particularly important where the Commission uses the midpoint of the zone of reasonableness because a single outlier can dramatically affect the resulting ROE.

C. <u>**Preliminary Results of Applying Proposed Approach to the First Complaint**</u>

55. Having described, above, our proposed approaches to determining whether (1) an existing ROE is unjust and unreasonable under the first prong of FPA section 206 and (2) if so, what the replacement ROE should be under the second prong of FPA section 206, we now explain how those approaches would apply in the First Complaint. This description represents the Commission's preliminary determinations as to how we should

resolve the issues remanded by the D.C. Circuit in *Emera Maine*. However, as described in the next section, we are directing participants to file briefs regarding our proposed approaches to the FPA section 206 inquiry and how they should apply in the First Complaint and the three subsequent complaints.

56. Under our proposed framework for determining whether NETOs' preexisting 11.14 percent ROE is unjust and unreasonable under the first prong of FPA section 206, we must first determine what a composite zone of reasonableness would be. For this purpose, we find that the DCF zone of reasonableness, as determined in Opinion No. 531 based on financial data from the period October 2012 through March 2013, is 7.03 percent to 11.74 percent.[112] Similarly, the CAPM zone of reasonableness as determined in Opinion No. 531 is 7.4 percent to 13.30 percent.[113] With the adjustment discussed in the preceding section, the Expected Earnings approach's zone of reasonableness is 8.10 percent to 14.20 percent. Averaging these results, we determine that the composite zone of reasonableness is 7.51 percent to 13.08 percent. The top of this new composite zone of reasonableness would also determine the cap for the total ROE, *i.e.*, the base ROE plus any ROE incentives.

57. It is undisputed that NETOs are of average risk. Accordingly, the range of presumptively just and reasonable ROEs for NETOs is the middle quartile of the composite zone of reasonableness.[114] As discussed above, this represents the "broad range of potentially lawful ROEs" for NETOs that the D.C. Circuit contemplated in *Emera Maine* for purposes of determining whether an existing ROE is unjust and unreasonable under the first prong of FPA section 206. Here, that range specifically corresponds to the one quarter of the overall zone of reasonableness centered around the 10.3 percent midpoint of the zone of reasonableness. That quarter of the 7.51 percent to 13.08 percent zone of reasonableness is 9.60 percent to 10.99 percent. NETOs' preexisting 11.14 percent ROE is outside this range of potentially lawful ROEs; it is closer to the current just and reasonable ROE for a utility of above average risk than for utilities of average risk such as NETOs. This supports a finding that an 11.14 percent

---

[112] *Id.* PP 9, 143.

[113] *Id.* P 147.

[114] NETOs being a diverse group of average risk utilities, the relevant central tendency is the midpoint. *See supra* n.45.

ROE is unjust and unreasonable for average risk utilities, such as NETOs. If any total ROEs—i.e., base ROE plus incentive ROE adders—exceed 13.08 percent, we would find these ROEs unjust and unreasonable as well.

58. Moreover, a finding that NETOs' preexisting 11.14 ROE has become unjust and unreasonable is buttressed by the substantial change in capital market conditions since Opinion No. 489 established that ROE. The 11.14 percent ROE was based on a DCF analysis using financial data from July to December 2004, with an adjustment to reflect an increase in average 10-year U.S. Treasury bond rates from that period to March to August 2006. During the March to August 2006 period, average utility bond yields ranged from 5.99 to 6.39 percent. By contrast, during the October 2012 to March 2013 period at issue in the First Complaint, utility bond yields ranged from 3.95 to 4.29 percent. The substantial reduction in utility bond yields since NETOs' preexisting 11.14 ROE was established buttresses a finding that capital market conditions have so changed as to render that ROE unjust and unreasonable. Based on these facts, we would reaffirm our holding in Opinion No. 531 that NETOs' preexisting ROE is unjust and unreasonable.

59. We thus turn to selecting a replacement just and reasonable ROE for NETOs. Under the approach outlined above, to select a replacement just and reasonable ROE we average the central tendencies of the zones of reasonableness produced by the DCF, CAPM, and Expected Earnings analyses together with the estimated cost of equity produced by the Risk Premium method, with each figure being given equal weight. Accordingly, we average the 9.39 percent midpoint of the DCF analysis, the 10.35 percent midpoint of the CAPM analysis, the 11.15 percent midpoint of the Expected Earnings analysis, and the 10.75 percent result of the Risk Premium analysis[115] to arrive at a preliminary 10.41 percent just and reasonable ROE for NETOs, exclusive of incentives. Further, we would cap any preexisting incentive-based total ROE above 13.08 percent at 13.08 percent.

60. If the Commission adopts this finding in its order following the briefing directed by this order, the Commission will exercise its "broad remedial authority" to correct its legal error in order to make the 10.41 percent ROE, exclusive of incentives, effective as

---

[115] *Id.* (NETOs' Risk Premium analysis indicated that NETOs' cost of equity is between 10.7 percent and 10.8 percent; therefore we use the 10.75 percent midpoint of that range).

of the October 16, 2014 date of Opinion No. 531-A, and the Commission will order refunds of amounts collected in excess of 10.41 percent pursuant to the 10.57 percent ROE established by that opinion.[116] Accordingly, the issue to be addressed in the Second Complaint is whether the ROE established on remand in the First Complaint remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the Second Complaint. Similarly, the Third and Fourth Complaints should address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

D. <u>Briefing</u>

61. As discussed above, we are directing the participants to these proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the First, Second, Third, and Fourth Complaints. The participants should submit separate briefs regarding each of the complaints. In addition, the participants may supplement the record with additional written evidence as necessary to support the arguments advanced in their briefs.[117] However, to the extent participants submit additional financial data or evidence concerning economic conditions in any proceeding it must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Any additional evidence shall be submitted in the form of affidavits accompanying the relevant brief(s). Initial briefs shall be due 60 days from the date of this order. Responses to those initial briefs shall be due 30 days later. No answers or additional briefs will be permitted.

---

[116] *ISO New England Inc.*, 161 FERC ¶ 61,031 at PP 24, 34.

[117] *See Consolidated Edison of N.Y., Inc. v. FERC*, 315 F.3d 316, 323 (D.C. Cir. 2003) (holding that the Commission may apply a new policy “retroactively to the parties in an ongoing adjudication, so long as the parties before the agency are given notice and an opportunity to offer evidence bearing on the new standard”) *Town of Norwood, Mass. v. FERC*, 80 F.3d 526, 535 (D.C. Cir. 1996) (holding that, “the Commission takes account of changes that occur between the ALJ’s decision and the Commission's review of that decision . . . the Commission may not depart from the zone of reasonableness on the basis of the change without giving parties an opportunity to reopen the record” (citing *Union Elec. Co. v. FERC*, 890 F.2d 1193, 1201-04 (D.C. Cir. 1989))); *see also Clark-Cowlitz Joint Operating Agency v. FERC*, 826 F.2d 1074, 1081 (D.C. Cir. 1987) (*en banc*) (discussing factors that the D.C. Circuit considers when determining whether it would be inappropriate to apply new policy retrospectively).

The Commission orders:

The participants are directed to submit supplemental briefs and additional written evidence, as discussed in the body of this order.

By the Commission. Commissioner Glick is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix

The four traditional methods investors may use to estimate the expected return from an investment in a company.

DCF Methodology

With simplifying assumptions, the formula for the DCF methodology reduces to: P = D/k-g, where “P” is the price of the common stock, “D” is the current dividend, “k” is the discount rate (or investors’ required rate of return), and “g” is the expected growth rate in dividends. For ratemaking purposes, the Commission rearranges the DCF formula to solve for “k”, the discount rate, which represents the rate of return that investors require to invest in a company’s common stock, and then multiplies the dividend yield by the expression (1+.5g) to account for the fact that dividends are paid on a quarterly basis. Multiplying the dividend yield by (1+.5g) increases the dividend yield by one half of the growth rate and produces what the Commission refers to as the “adjusted dividend yield.” The resulting formula is known as the constant growth DCF methodology and can be expressed as follows: k=D/P (1+.5g) + g. Under the Commission’s two-step DCF methodology, the input for the expected dividend growth rate, “g,” is calculated using both short-term and long-term growth projections.[118] Those two growth rate estimates are averaged, with the short-term growth rate estimate receiving two-thirds weighting and the long-term growth rate estimate receiving one-third weighting.[119]

CAPM

Investors use CAPM analysis as a measure of the cost of equity relative to risk.[120] The CAPM methodology is based on the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. Specifically, the CAPM methodology estimates the cost of equity by taking the “risk-free rate” and adding to it the “market-risk premium” multiplied by “beta.”[121] The risk-free rate is represented by a proxy, typically the yield on 30-year U.S. Treasury bonds.[122] Betas, which are published by several commercial sources, measure a specific

[118] Opinion No. 531, 147 FERC ¶ 61,234 at PP 15-17, 36-40; Opinion No. 531-A, 149 FERC ¶ 61,032 at P 10.

[119] Opinion No. 531, 147 FERC ¶ 61,234 at PP 17, 39.

[120] *Id.* P 147.

[121] Morin at 150.

[122] *Id.* at 151.

stock's risk relative to the market. The market risk premium is calculated by subtracting the risk-free rate from the expected return. The expected return can be estimated either using a backward-looking approach, a forward-looking approach, or a survey of academics and investment professionals.[123] A CAPM analysis is backward-looking if the expected return is determined based on historical, realized returns.[124] A CAPM analysis is forward-looking if the expected return is based on a DCF analysis of a large segment of the market.[125] Thus, in a forward-looking CAPM analysis, the market risk premium is calculated by subtracting the risk-free rate from the result produced by the DCF analysis.[126]

Risk Premium

The risk premium methodology, in which interest rates are also a direct input, is "based on the simple idea that since investors in stocks take greater risk than investors in bonds, the former expect to earn a return on a stock investment that reflects a 'premium' over and above the return they expect to earn on a bond investment."[127] As the Commission found in Opinion No. 531, investors' required risk premiums expand with low interest rates and shrink at higher interest rates. The link between interest rates and risk premiums provides a helpful indicator of how investors' required rate of return have been impacted by the interest rate environment.

Multiple approaches have been advanced to determine the equity risk premium for a utility.[128] For example, a risk premium can be developed directly, by conducting a risk premium analysis for the company at issue, or indirectly by conducting a risk premium analysis for the market as a whole and then adjusting that result to reflect the risk of the company at issue.[129] Another approach for the utility context is to "examin[e] the risk premiums implied in the returns on equity allowed by regulatory commissions for utilities

---

[123] *Id.* at 155-162.

[124] *Id.* at 155-156.

[125] *Id.* at 159-160.

[126] *See id.* at 150, 155.

[127] Opinion No. 531, 147 FERC ¶ 61,234 at P 147 (citing Morin at 108).

[128] *See generally* Morin at 107-130.

[129] *Id.* at 110.

over some past period relative to the contemporaneous level of the long-term U.S. Treasury bond yield."[130]

<u>Expected Earnings</u>

A comparable earnings analysis is a method of calculating the earnings an investor expects to receive on the book value of a particular stock. The analysis can be either backward looking using the company's historical earnings on book value, as reflected on the company's accounting statements, or forward-looking using estimates of earnings on book value, as reflected in analysts' earnings forecasts for the company.[131] The latter approach is often referred to as an "Expected Earnings analysis." The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's cost of equity, because those returns on book equity help investors determine the opportunity cost of investing in that particular utility instead of other companies of comparable risk.[132] Because investors rely on Expected Earnings analyses to help estimate the opportunity cost of investing in a particular utility, we find this type of analysis useful in determining a utility's ROE.

[130] *Id.* at 123.

[131] *See* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 125.

[132] *Id.* P 128.

FEDERAL RESERVE press release

For release at 2 p.m. EDT September 26, 2018

Information received since the Federal Open Market Committee met in August indicates that the labor market has continued to strengthen and that economic activity has been rising at a strong rate. Job gains have been strong, on average, in recent months, and the unemployment rate has stayed low. Household spending and business fixed investment have grown strongly. On a 12-month basis, both overall inflation and inflation for items other than food and energy remain near 2 percent. Indicators of longer-term inflation expectations are little changed, on balance.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee expects that further gradual increases in the target range for the federal funds rate will be consistent with sustained expansion of economic activity, strong labor market conditions, and inflation near the Committee's symmetric 2 percent objective over the medium term. Risks to the economic outlook appear roughly balanced.

In view of realized and expected labor market conditions and inflation, the Committee decided to raise the target range for the federal funds rate to 2 to 2-1/4 percent.

In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its maximum employment objective and its symmetric 2 percent inflation objective. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments.

Voting for the FOMC monetary policy action were: Jerome H. Powell, Chairman; John C. Williams, Vice Chairman; Thomas I. Barkin; Raphael W. Bostic; Lael Brainard; Richard H. Clarida; Esther L. George; Loretta J. Mester; and Randal K. Quarles.

For release at 2 p.m. EDT September 26, 2018

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee (FOMC) in its statement on September 26, 2018:

- The Board of Governors of the Federal Reserve System voted unanimously to raise the interest rate paid on required and excess reserve balances to 2.20 percent, effective September 27, 2018.

- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

> "Effective September 27, 2018, the Federal Open Market Committee directs the Desk to undertake open market operations as necessary to maintain the federal funds rate in a target range of 2 to 2-1/4 percent, including overnight reverse repurchase operations (and reverse repurchase operations with maturities of more than one day when necessary to accommodate weekend, holiday, or similar trading conventions) at an offering rate of 2.00 percent, in amounts limited only by the value of Treasury securities held outright in the System Open Market Account that are available for such operations and by a per-counterparty limit of $30 billion per day.
>
> The Committee directs the Desk to continue rolling over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing during September that exceeds $24 billion, and to continue reinvesting in agency mortgage-backed securities the amount of principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities received during September that exceeds $16 billion. Effective in October, the Committee directs the Desk to roll over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing during each calendar month that exceeds $30 billion, and to reinvest in agency mortgage-backed securities the amount of principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities received during each calendar month that exceeds $20 billion. Small deviations from these amounts for operational reasons are acceptable.
>
> The Committee also directs the Desk to engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency mortgage-backed securities transactions."

(more)

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1/4 percentage point increase in the primary credit rate to 2.75 percent, effective September 27, 2018. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Boston, Philadelphia, Cleveland, Richmond, Atlanta, Chicago, St. Louis, Kansas City, Dallas, and San Francisco.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website.

FEDERAL RESERVE press release

For release at 2 p.m. EDT June 13, 2018

Information received since the Federal Open Market Committee met in May indicates that the labor market has continued to strengthen and that economic activity has been rising at a solid rate. Job gains have been strong, on average, in recent months, and the unemployment rate has declined. Recent data suggest that growth of household spending has picked up, while business fixed investment has continued to grow strongly. On a 12-month basis, both overall inflation and inflation for items other than food and energy have moved close to 2 percent. Indicators of longer-term inflation expectations are little changed, on balance.

Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee expects that further gradual increases in the target range for the federal funds rate will be consistent with sustained expansion of economic activity, strong labor market conditions, and inflation near the Committee's symmetric 2 percent objective over the medium term. Risks to the economic outlook appear roughly balanced.

In view of realized and expected labor market conditions and inflation, the Committee decided to raise the target range for the federal funds rate to 1-3/4 to 2 percent. The stance of monetary policy remains accommodative, thereby supporting strong labor market conditions and a sustained return to 2 percent inflation.

In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its maximum employment objective and its symmetric 2 percent inflation objective. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments.

Voting for the FOMC monetary policy action were Jerome H. Powell, Chairman; William C. Dudley, Vice Chairman; Thomas I. Barkin; Raphael W. Bostic; Lael Brainard; Loretta J. Mester; Randal K. Quarles; and John C. Williams.

For release at 2 p.m. EDT June 13, 2018

Decisions Regarding Monetary Policy Implementation

The Federal Reserve has made the following decisions to implement the monetary policy stance announced by the Federal Open Market Committee (FOMC) in its statement on June 13, 2018:

- The Board of Governors of the Federal Reserve System voted unanimously to raise the interest rate paid on required and excess reserve balances to 1.95 percent, effective June 14, 2018. Setting the interest rate paid on required and excess reserve balances 5 basis points below the top of the target range for the federal funds rate is intended to foster trading in the federal funds market at rates well within the FOMC's target range.
- As part of its policy decision, the Federal Open Market Committee voted to authorize and direct the Open Market Desk at the Federal Reserve Bank of New York, until instructed otherwise, to execute transactions in the System Open Market Account in accordance with the following domestic policy directive:

> "Effective June 14, 2018, the Federal Open Market Committee directs the Desk to undertake open market operations as necessary to maintain the federal funds rate in a target range of 1-3/4 to 2 percent, including overnight reverse repurchase operations (and reverse repurchase operations with maturities of more than one day when necessary to accommodate weekend, holiday, or similar trading conventions) at an offering rate of 1.75 percent, in amounts limited only by the value of Treasury securities held outright in the System Open Market Account that are available for such operations and by a per-counterparty limit of $30 billion per day.
>
> The Committee directs the Desk to continue rolling over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing during June that exceeds $18 billion, and to continue reinvesting in agency mortgage-backed securities the amount of principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities received during June that exceeds $12 billion. Effective in July, the Committee directs the Desk to roll over at auction the amount of principal payments from the Federal Reserve's holdings of Treasury securities maturing during each calendar month that exceeds $24 billion, and to reinvest in agency mortgage-backed securities the amount of principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities received during each calendar month that exceeds $16 billion. Small deviations from these amounts for operational reasons are acceptable.
>
> The Committee also directs the Desk to engage in dollar roll and coupon swap transactions as necessary to facilitate settlement of the Federal Reserve's agency mortgage-backed securities transactions."

(more)

- In a related action, the Board of Governors of the Federal Reserve System voted unanimously to approve a 1/4 percentage point increase in the primary credit rate to 2.50 percent, effective June 14, 2018. In taking this action, the Board approved requests to establish that rate submitted by the Boards of Directors of the Federal Reserve Banks of Boston, Philadelphia, Cleveland, Richmond, Atlanta, Chicago, St. Louis, Minneapolis, Kansas City, Dallas, and San Francisco.

This information will be updated as appropriate to reflect decisions of the Federal Open Market Committee or the Board of Governors regarding details of the Federal Reserve's operational tools and approach used to implement monetary policy.

More information regarding open market operations and reinvestments may be found on the Federal Reserve Bank of New York's website.

For release at 2:00 p.m., EDT, September 26, 2018

Economic projections of Federal Reserve Board members and Federal Reserve Bank presidents under their individual assessments of projected appropriate monetary policy, September 2018

Advance release of table 1 of the Summary of Economic Projections to be released with the FOMC minutes

Percent

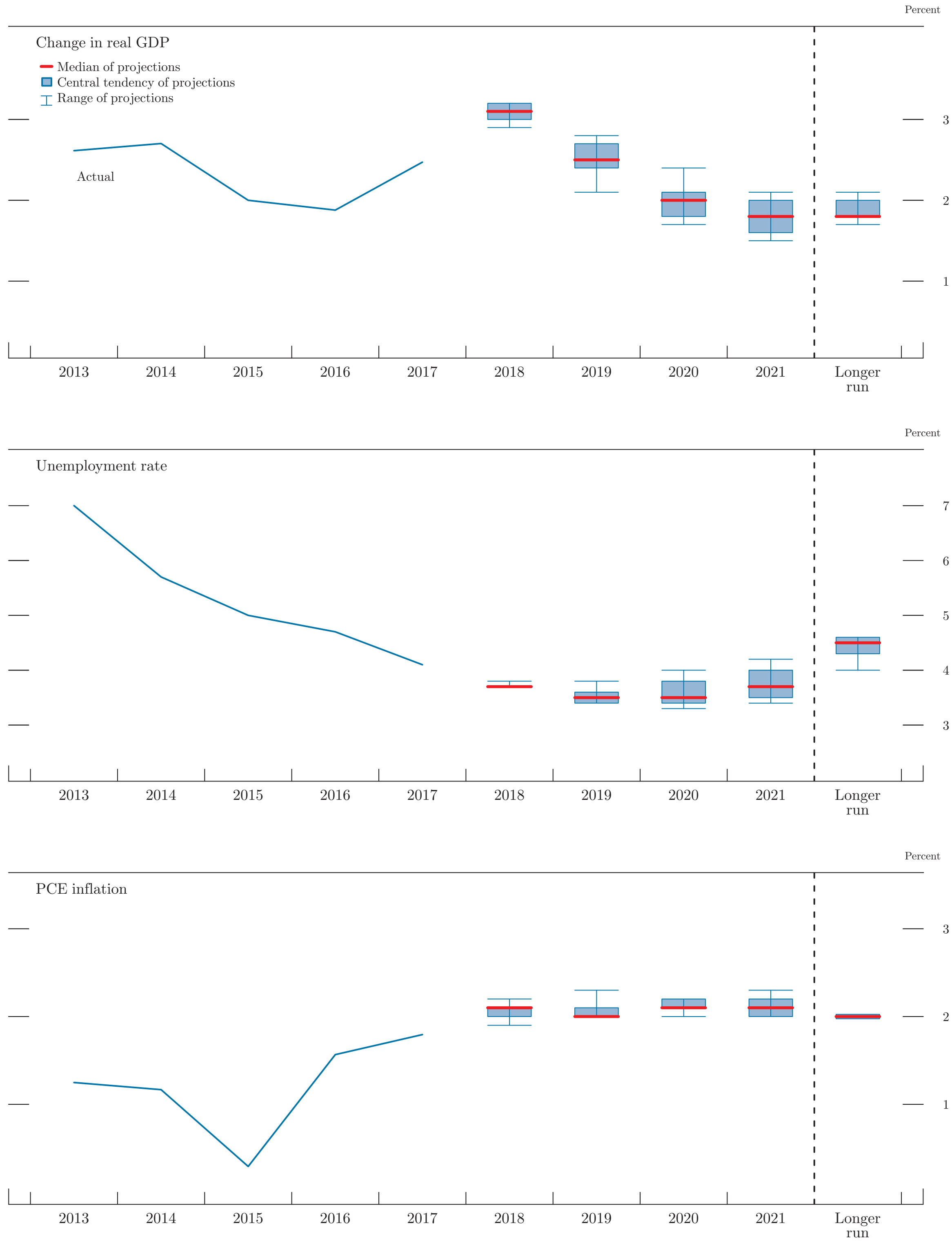
Variable	Median[1]					Central tendency[2]					Range[3]				
	2018	2019	2020	2021	Longer run	2018	2019	2020	2021	Longer run	2018	2019	2020	2021	Longer run
Change in real GDP	3.1	2.5	2.0	1.8	1.8	3.0 – 3.2	2.4 – 2.7	1.8 – 2.1	1.6 – 2.0	1.8 – 2.0	2.9 – 3.2	2.1 – 2.8	1.7 – 2.4	1.5 – 2.1	1.7 – 2.1
June projection	2.8	2.4	2.0	n.a.	1.8	2.7 – 3.0	2.2 – 2.6	1.8 – 2.0	n.a.	1.8 – 2.0	2.5 – 3.0	2.1 – 2.7	1.5 – 2.2	n.a.	1.7 – 2.1
Unemployment rate	3.7	3.5	3.5	3.7	4.5	3.7	3.4 – 3.6	3.4 – 3.8	3.5 – 4.0	4.3 – 4.6	3.7 – 3.8	3.4 – 3.8	3.3 – 4.0	3.4 – 4.2	4.0 – 4.6
June projection	3.6	3.5	3.5	n.a.	4.5	3.6 – 3.7	3.4 – 3.5	3.4 – 3.7	n.a.	4.3 – 4.6	3.5 – 3.8	3.3 – 3.8	3.3 – 4.0	n.a.	4.1 – 4.7
PCE inflation	2.1	2.0	2.1	2.1	2.0	2.0 – 2.1	2.0 – 2.1	2.1 – 2.2	2.0 – 2.2	2.0	1.9 – 2.2	2.0 – 2.3	2.0 – 2.2	2.0 – 2.3	2.0
June projection	2.1	2.1	2.1	n.a.	2.0	2.0 – 2.1	2.0 – 2.2	2.1 – 2.2	n.a.	2.0	2.0 – 2.2	1.9 – 2.3	2.0 – 2.3	n.a.	2.0
Core PCE inflation[4]	2.0	2.1	2.1	2.1		1.9 – 2.0	2.0 – 2.1	2.1 – 2.2	2.0 – 2.2		1.9 – 2.0	2.0 – 2.3	2.0 – 2.2	2.0 – 2.3	
June projection	2.0	2.1	2.1	n.a.		1.9 – 2.0	2.0 – 2.2	2.1 – 2.2	n.a.		1.9 – 2.1	2.0 – 2.3	2.0 – 2.3	n.a.	
Memo: Projected appropriate policy path															
Federal funds rate	2.4	3.1	3.4	3.4	3.0	2.1 – 2.4	2.9 – 3.4	3.1 – 3.6	2.9 – 3.6	2.8 – 3.0	2.1 – 2.4	2.1 – 3.6	2.1 – 3.9	2.1 – 4.1	2.5 – 3.5
June projection	2.4	3.1	3.4	n.a.	2.9	2.1 – 2.4	2.9 – 3.4	3.1 – 3.6	n.a.	2.8 – 3.0	1.9 – 2.6	1.9 – 3.6	1.9 – 4.1	n.a.	2.3 – 3.5

NOTE: Projections of change in real gross domestic product (GDP) and projections for both measures of inflation are percent changes from the fourth quarter of the previous year to the fourth quarter of the year indicated. PCE inflation and core PCE inflation are the percentage rates of change in, respectively, the price index for personal consumption expenditures (PCE) and the price index for PCE excluding food and energy. Projections for the unemployment rate are for the average civilian unemployment rate in the fourth quarter of the year indicated. Each participant's projections are based on his or her assessment of appropriate monetary policy. Longer-run projections represent each participant's assessment of the rate to which each variable would be expected to converge under appropriate monetary policy and in the absence of further shocks to the economy. The projections for the federal funds rate are the value of the midpoint of the projected appropriate target range for the federal funds rate or the projected appropriate target level for the federal funds rate at the end of the specified calendar year or over the longer run. The June projections were made in conjunction with the meeting of the Federal Open Market Committee on June 12–13, 2018. One participant did not submit longer-run projections for the change in real GDP, the unemployment rate, or the federal funds rate in conjunction with the June 12–13, 2018, meeting, and one participant did not submit such projections in conjunction with the September 25–26, 2018, meeting.

1. For each period, the median is the middle projection when the projections are arranged from lowest to highest. When the number of projections is even, the median is the average of the two middle projections.
2. The central tendency excludes the three highest and three lowest projections for each variable in each year.
3. The range for a variable in a given year includes all participants' projections, from lowest to highest, for that variable in that year.
4. Longer-run projections for core PCE inflation are not collected.

For release at 2:00 p.m., EDT, September 26, 2018

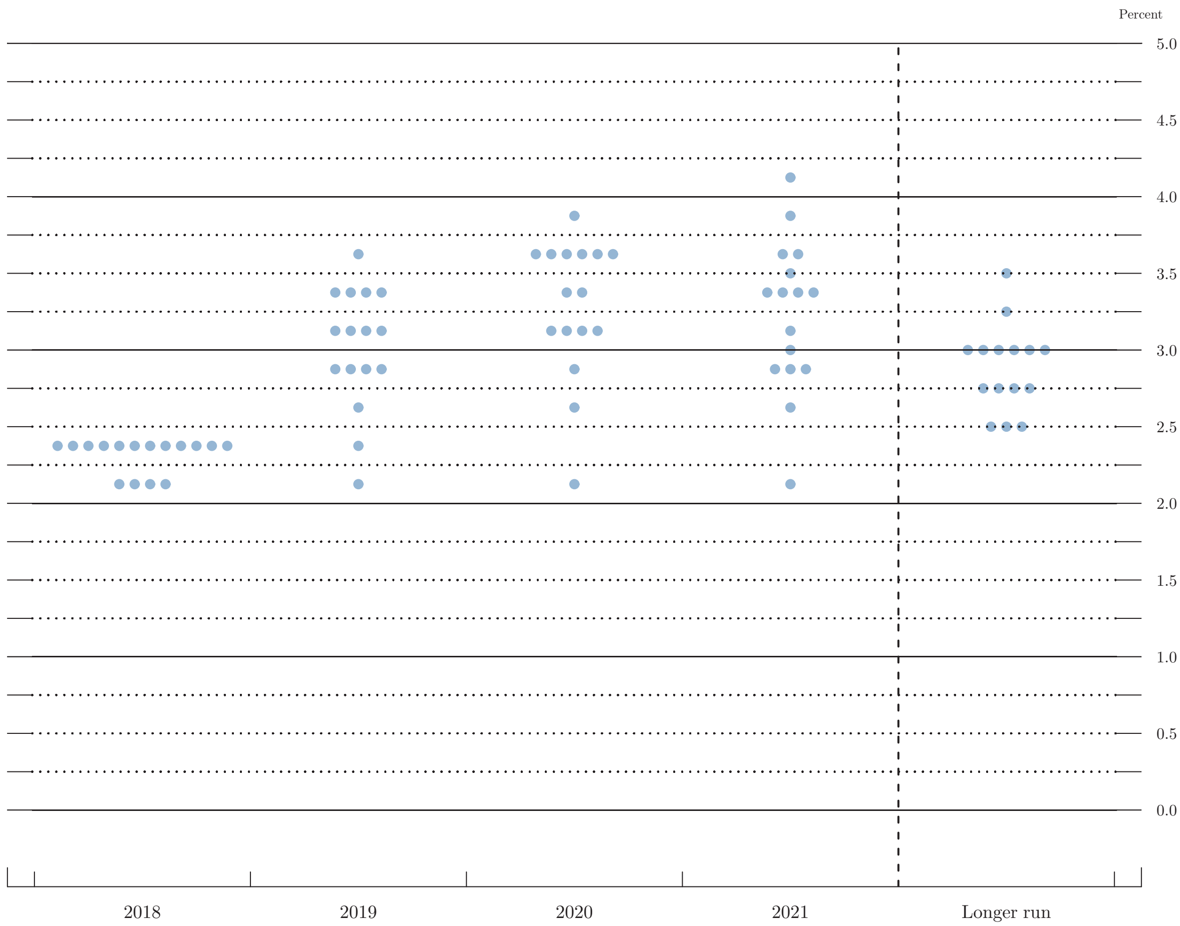
Figure 1. Medians, central tendencies, and ranges of economic projections, 2018–21 and over the longer run



NOTE: Definitions of variables and other explanations are in the notes to the projections table. The data for the actual values of the variables are annual.

For release at 2:00 p.m., EDT, September 26, 2018

Figure 2. FOMC participants' assessments of appropriate monetary policy: Midpoint of target range or target level for the federal funds rate



Note: Each shaded circle indicates the value (rounded to the nearest 1/8 percentage point) of an individual participant's judgment of the midpoint of the appropriate target range for the federal funds rate or the appropriate target level for the federal funds rate at the end of the specified calendar year or over the longer run. One participant did not submit longer-run projections for the federal funds rate.

Explanation of Economic Projections Charts

The charts show actual values and projections for three economic variables, based on FOMC participants' individual assessments of appropriate monetary policy:

- Change in Real Gross Domestic Product (GDP)—as measured from the fourth quarter of the previous year to the fourth quarter of the year indicated.
- Unemployment Rate—the average civilian unemployment rate in the fourth quarter of each year.
- PCE Inflation—as measured by the change in the personal consumption expenditures (PCE) price index from the fourth quarter of the previous year to the fourth quarter of the year indicated.

Information for these variables is shown for each year from 2013 to 2021, and for the longer run.

The solid blue line, labeled "Actual," shows the historical values for each variable.

The solid red lines depict the median projection in each period for each variable. The median value in each period is the middle projection when the projections are arranged from lowest to highest. When the number of projections is even, the median is the average of the two middle projections.

The range and central tendency for each variable in each projection period are depicted in "box and whiskers" format. The blue connected horizontal and vertical lines ("whiskers") represent the range of the projections of policymakers. The bottom of the range for each variable is the lowest of all of the projections for that year or period. Likewise, the top of the range is the highest of all of the projections for that year or period. The light blue shaded boxes represent the central tendency, which is a narrower version of the range that excludes the three highest and three lowest projections for each variable in each year or period.

The longer-run projections, which are shown on the far right side of the charts, are the rates of growth, unemployment, and inflation to which a policymaker expects the economy to converge over time—maybe in five or six years—in the absence of further shocks and under appropriate monetary policy. Because appropriate monetary policy, by definition, is aimed at achieving the Federal Reserve's dual mandate of maximum employment and price stability in the longer run, policymakers' longer-run projections for economic growth and unemployment may be interpreted, respectively, as estimates of the economy's normal or trend rate of growth and its normal unemployment rate over the longer run. The longer-run projection shown for inflation is the rate of inflation judged to be most consistent with the Federal Reserve's dual mandate.

For release at 2:00 p.m., EDT, September 26, 2018

Explanation of Policy Path Chart

This chart is based on policymakers' assessments of appropriate monetary policy, which, by definition, is the future path of policy that each participant deems most likely to foster outcomes for economic activity and inflation that best satisfy his or her interpretation of the Federal Reserve's dual objectives of maximum employment and stable prices.

Each shaded circle indicates the value (rounded to the nearest ⅛ percentage point) of an individual participant's judgment of the midpoint of the appropriate target range for the federal funds rate or the appropriate target level for the federal funds rate at the end of the specified calendar year or over the longer run.

FEDERAL RESERVE press release

For release at 2 p.m. EDT June 14, 2017

Addendum to the Policy Normalization Principles and Plans

All participants agreed to augment the Committee's Policy Normalization Principles and Plans by providing the following additional details regarding the approach the FOMC intends to use to reduce the Federal Reserve's holdings of Treasury and agency securities once normalization of the level of the federal funds rate is well under way.[1]

- The Committee intends to gradually reduce the Federal Reserve's securities holdings by decreasing its reinvestment of the principal payments it receives from securities held in the System Open Market Account. Specifically, such payments will be reinvested only to the extent that they exceed gradually rising caps.
  - For payments of principal that the Federal Reserve receives from maturing Treasury securities, the Committee anticipates that the cap will be $6 billion per month initially and will increase in steps of $6 billion at three-month intervals over 12 months until it reaches $30 billion per month.
  - For payments of principal that the Federal Reserve receives from its holdings of agency debt and mortgage-backed securities, the Committee anticipates that the cap will be $4 billion per month initially and will increase in steps of $4 billion at three-month intervals over 12 months until it reaches $20 billion per month.
  - The Committee also anticipates that the caps will remain in place once they reach their respective maximums so that the Federal Reserve's securities holdings will

(more)

[1] The Committee's Policy Normalization Principles and Plans were adopted on September 16, 2014, and are available at www.federalreserve.gov/monetarypolicy/files/FOMC_PolicyNormalization.pdf. On March 18, 2015, the Committee adopted an addendum to the Policy Normalization Principles and Plans, which is available at www.federalreserve.gov/monetarypolicy/files/FOMC_PolicyNormalization.20150318.pdf.

continue to decline in a gradual and predictable manner until the Committee judges that the Federal Reserve is holding no more securities than necessary to implement monetary policy efficiently and effectively.

- Gradually reducing the Federal Reserve's securities holdings will result in a declining supply of reserve balances. The Committee currently anticipates reducing the quantity of reserve balances, over time, to a level appreciably below that seen in recent years but larger than before the financial crisis; the level will reflect the banking system's demand for reserve balances and the Committee's decisions about how to implement monetary policy most efficiently and effectively in the future. The Committee expects to learn more about the underlying demand for reserves during the process of balance sheet normalization.
- The Committee affirms that changing the target range for the federal funds rate is its primary means of adjusting the stance of monetary policy. However, the Committee would be prepared to resume reinvestment of principal payments received on securities held by the Federal Reserve if a material deterioration in the economic outlook were to warrant a sizable reduction in the Committee's target for the federal funds rate. Moreover, the Committee would be prepared to use its full range of tools, including altering the size and composition of its balance sheet, if future economic conditions were to warrant a more accommodative monetary policy than can be achieved solely by reducing the federal funds rate.

- 0 -

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

Vol. 37, No. 10, October 1, 2018

Wolters Kluwer

BLUE CHIP FINANCIAL FORECASTS®

Executive Editor:
Joseph Aguinaldo
Director of Data Research & Documentation
Haver Analytics
60 East 42nd Street
New York, NY 10165
Phone (212) 986-9300
E-mail: *bluechip@haver.com*

Founder: Robert J. Eggert
Randell E. Moore, Editor Emeritus
Dom Cervi, Publisher

Blue Chip Financial Forecasts® (ISSN: 0741-8345) is published monthly by CCH Incorporated, 76 Ninth Avenue, New York, NY 10011. Printed in the U.S.A.

Subscriptions: $1,595 per year for print delivery of 12 monthly issues. For alternate formats (PDF, Excel, online), multiple-copy rates and site-license agreements call Nelson Pereira in the U.S. at 212-771-0701. You may also contact him at: nelson.pereira@wolterskluwer.com

Permission requests: For information on how to obtain permission to reproduce content, please visit the Wolters Kluwer website at: https://lrus.wolterskluwer.com/policies/permissions-reprints-and-licensing/

Purchasing reprints: For customized article reprints, please contact *Wright's Media* at 1-877-652-5295 or go to the *Wright's Media* website at *www.wrightsmedia.com.*

Customer Service: 1-800-234-1660
To Order: 1-800-638-8437
Customer Service Fax: 1-800-901-9075
Email: customer.service@wolterskluwer.com
Web Site:
https://lrus.wolterskluwer.com/corporate/blue-chip/

TABLE OF CONTENTS

Another Fed Rate Hike Likely in December; Modestly Higher Rates Seen Through 2019

Domestic Commentary & Consensus Fed Forecast. The Federal Open Market Committee raised the federal funds rate at their meeting last week to a new target range of 2.00%-2.25%, as had been universally expected in our late August survey. Moving ahead, in our September 26-27 survey, 93% of the Blue Chip Financial Forecasts panel looks for the FOMC to raise the fed funds rate range again at their December 18-19 meeting, thus ending the year at a midpoint of 2.375%.

Beyond this latest action, it's obviously important to know the take-off point for upcoming financial activity. So our first Special Question this month asks about panelists' estimates of Q3 GDP and inflation. The panel consensus puts GDP growth at 3.2% and both the GDP price index and the CPI up at 2.2% rates. Thus, growth is seen to be still firm after the 4.2% surge in Q2, and inflation just above the Fed's 2% target.

For 2019, the panel anticipates further tightening, although as has been the case in the last several months' surveys, there remains wide variation. As shown in the Special Questions, 16% of the panel look for just 25 basis points during the year, 25% expect 50 basis points and 36%, 75 basis points, with a few seeing no tightening at all, and several projecting a full percentage point. The consensus average suggests a total increase across the year of about 50 basis points, from 2.375% in December 2018 to 2.875% during Q4 2019 and persisting into Q1 2020.

Notably, the Federal Open Market Committee appears to anticipate more tightening than the Blue Chip Financial Forecasts panel does. The dot-plot accompanying this recent FOMC meeting shows that a majority of those 16 policymakers (12 Federal Reserve Bank Presidents and four Board members) anticipate that the fed funds rate will surpass 3% during Q4 2019, with the average of all their individual forecasts right at 3% for late in that year.

The FOMC's slightly higher funds rate expectations accompany an economic forecast that is slightly stronger than that of the Blue Chip panel. The Fed's Summary of Economic Projections shows GDP growth at 3.1% this year, Q4 over Q4, followed by 2.5% across next year. Our Blue Chip Financial panel's consensus is modestly lower for 2019, at 2.4%. Thus, it's not surprising that the Fed itself might anticipate the need for somewhat more tightening than the Blue Chip panel does. In fact, the quarterly pattern in the Blue Chip forecast shows growth slowing noticeably during next year, from 2.4% in both Q1 and Q2, then to 2.2% in Q3 and just 1.9% in Q4 with 1.8% in Q1 2020. Less action from the Fed would follow naturally from that tapering of growth.

On the other hand, the Fed's forecasts look for marginally lower inflation than do the panelists'. The Fed concentrates on the PCE price index and they project 2.1% this year, Q4 over Q4, followed by 2.0% across 2019. We asked a Special Question about this price measure, and the consensus returns the same 2.1% this year, December over December, but 2.2% across 2019, that is, a slight pick-up in inflation, rather than the marginal reduction the Fed shows. Lags in the impact of interest rate policies mean we probably cannot attribute the lower inflation in the Fed's forecast to their extra tightening moves, compared to the panel's expectations. And these differences are small anyway. But they do suggest somewhat differing forces in place moving forward.

Entering 2020, which the Blue Chip panel explores for the first time this month, they expect a steady funds rate at 2.9%, the same as in Q4 2019. The FOMC, by contrast, looks to further tightening, raising the rate over the course of that whole year to 3.4%.

While the panel's early-2020 forecast suggests that this tightening cycle might be concluding by then, their answers to a specific Special Question suggest that a least some more will go on. The consensus for the peak rate of this cycle is 3.21%, with estimates ranging from 2.6% all the way to 4.0%. Nearly half of the panel – 49% – also indicated that their peak rate would be above the long-run neutral fed funds rate, and another 41% said it would be equal to that rate. The Fed policymakers' long-term estimate of the funds rate is 3.0%, suggesting that they too believe their current tightening will carry the rate above such a long-term "equilibrium." It's no surprise, then, that their long-run growth estimate, 1.8%, is below the current short-run pace of growth.

Risks to the Outlook. The statement issued by the FOMC at the conclusion of their meeting last week contains two qualitative ingredients suggesting a steady move toward that long-run fed funds rate and an accompanying very moderate growth path. First, the Committee has dropped the word "accommodative" from its policy description. Also, the FOMC says, "Risks to the economic outlook appear roughly balanced." Thus, its gradual policy tightening seems to be intended to let the orderly growth of the economy continue while trying to ensure that inflation doesn't accelerate to such an extent that harsh remedies become necessary.

Perhaps the most visible risk to the economic outlook at the moment still seems to be the potential for a trade war. So we again asked the panel about the impact the current trade and tariff disputes might have on GDP growth. Last month, 73% of the panel said they didn't think the trade situation would affect growth, and among the 27% who did, the average cut to GDP was seen as 0.1% this year and 0.2% in 2019. This month, the evolution of the responses is mixed. More people believe growth will be affected, 43% of respondents this year, but the amount of the hit is so small, it rounds to zero and a few panelists even think growth could be lifted marginally. For next year, more than half, 54%, look for some effect, but again, it rounds to zero, and there are again a few who think that effect might be positive.

Besides limited inflation, the Fed's other standard policy goal is healthy labor markets. Their own forecast of the unemployment rate points to 3.7% this December and 3.5% at the end of 2019. The Blue Chip panelists also have 3.7% this December, but 3.6% at the end of next year. In the long-run, the Fed policymakers believe the rate will go back up as far as 4.5%.

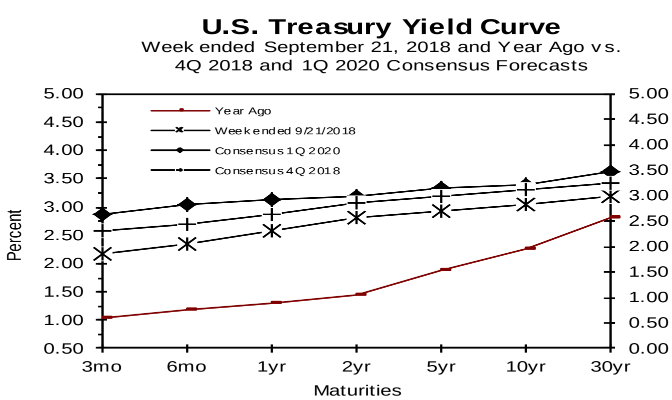
The shape of the yield curve also remains a matter of concern, a kind of risk. As business cycles mature, the yield curve flattens and eventually can become negative, as higher short-term yields overtake long-term yields. Such inverted curves often spell the onset of recession, partly due to the relative expense of borrowing short-term operating funds. The Blue Chip panel forecasts don't show this, as the consensus calls for a modest narrowing of the 10-year Treasury yield over the 2-year from 25 basis points currently to 18-21 basis points late next year. Further, in a Special Question, we asked again this month about the probability of an inversion happening; just 10% of the panel thinks that can happen during the rest of 2018 and 23% during 2019. So that risk to the economic outlook appears quite limited.

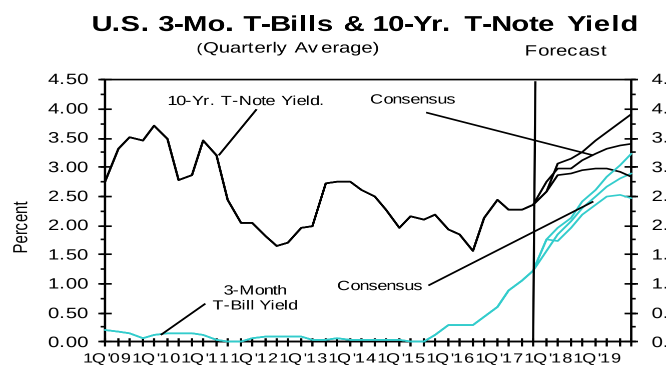
Another risk measure is the spread among yields on various qualities of credit. The survey's key measure of this would be the spread of corporate bonds over Treasuries. The panel sees AAA corporate yields, which are presently around 4.15%, rising to 4.3% during Q4 and 4.6% by late 2019. Compared to 30-year Treasuries, that's move from a recent spread of 1.0% to about 1.10% in Q3 and Q4 next year. Over the last nine years, this spread has averaged 1.18% and ahead of the milder 2001 recession, it did reach modestly above 2.00%.All of these risk conditions suggest that the probability of recession should not be high. And indeed it is not. The panel sees a mere 8.7% chance that a recession could set in yet this year, rising to 23.8% next year and 32.0% in 2020. *Carol Stone (Haver Analytics, NY, NY)*

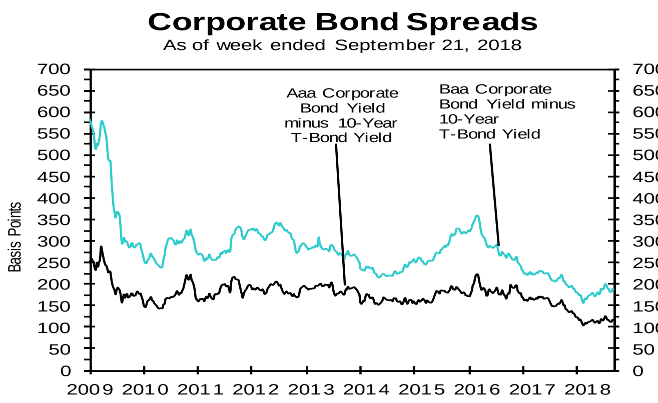
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

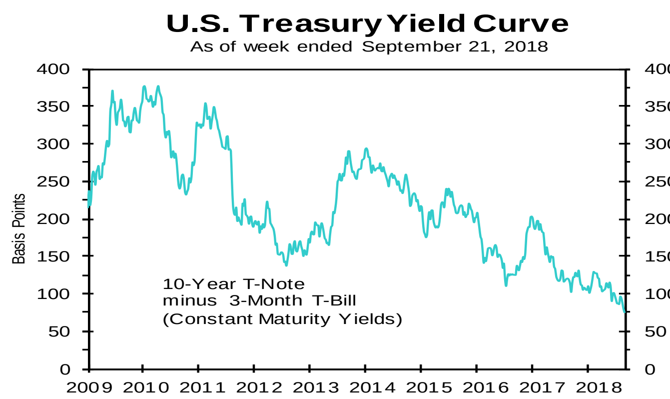
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Qtr	4Q	1Q	2Q	3Q	4Q	1Q
Interest Rates	Sep 21	Sep 14	Sep 7	Aug 31	Aug	Jul	Jun	*Q3 2018**	**2018**	**2019**	**2019**	**2019**	**2019**	**2020**
Federal Funds Rate	1.92	1.92	1.91	1.92	1.91	1.91	1.81	*1.91*	**2.2**	**2.4**	**2.7**	**2.8**	**2.9**	**2.9**
Prime Rate	5.00	5.00	5.00	5.00	5.00	5.00	4.88	*5.00*	**5.3**	**5.5**	**5.7**	**5.9**	**6.0**	**5.9**
LIBOR, 3-mo.	2.35	2.33	2.32	2.32	2.33	2.34	2.33	*2.33*	**2.6**	**2.8**	**3.0**	**3.1**	**3.2**	**3.2**
Commercial Paper, 1-mo.	2.10	2.03	2.00	1.99	1.96	1.96	1.92	*1.98*	**2.3**	**2.5**	**2.7**	**2.8**	**2.9**	**2.9**
Treasury bill, 3-mo.	2.17	2.15	2.14	2.12	2.07	1.99	1.94	*2.06*	**2.3**	**2.5**	**2.7**	**2.8**	**2.9**	**2.9**
Treasury bill, 6-mo.	2.36	2.32	2.30	2.27	2.24	2.16	2.11	*2.24*	**2.4**	**2.6**	**2.8**	**2.9**	**3.0**	**3.0**
Treasury bill, 1 yr.	2.58	2.55	2.50	2.47	2.45	2.38	2.31	*2.45*	**2.6**	**2.8**	**2.9**	**3.1**	**3.1**	**3.1**
Treasury note, 2 yr.	2.80	2.75	2.67	2.65	2.64	2.60	2.51	*2.65*	**2.8**	**3.0**	**3.1**	**3.2**	**3.2**	**3.2**
Treasury note, 5 yr.	2.94	2.87	2.78	2.76	2.77	2.77	2.76	*2.80*	**3.0**	**3.1**	**3.2**	**3.3**	**3.3**	**3.3**
Treasury note, 10 yr.	3.05	2.97	2.91	2.87	2.90	2.88	2.90	*2.91*	**3.1**	**3.2**	**3.3**	**3.4**	**3.4**	**3.4**
Treasury note, 30 yr.	3.19	3.11	3.08	3.01	3.05	3.00	3.04	*3.05*	**3.3**	**3.4**	**3.5**	**3.6**	**3.7**	**3.6**
Corporate Aaa bond	4.17	4.12	4.10	4.03	4.04	4.06	4.09	*4.07*	**4.3**	**4.5**	**4.6**	**4.7**	**4.7**	**4.7**
Corporate Baa bond	4.86	4.83	4.82	4.75	4.75	4.79	4.81	*4.78*	**5.1**	**5.3**	**5.4**	**5.5**	**5.6**	**5.6**
State & Local bonds	3.75	3.71	3.67	3.63	3.63	3.60	3.62	*3.64*	**4.0**	**4.1**	**4.2**	**4.3**	**4.4**	**4.4**
Home mortgage rate	4.65	4.60	4.54	4.52	4.55	4.53	4.57	*4.57*	**4.7**	**4.9**	**5.0**	**5.1**	**5.1**	**5.2**
	History								Consensus Forecasts-Quarterly					
	4Q	1Q	2Q	3Q	4Q	1Q	2Q	*3Q*	**4Q**	**1Q**	**2Q**	**3Q**	**4Q**	**1Q**
Key Assumptions	2016	2017	2017	2017	2017	2018	2018	*2018**	**2018**	**2019**	**2019**	**2019**	**2019**	**2020**
Major Currency Index	93.6	94.3	92.9	88.3	88.9	86.1	88.3	*90.2*	**90.0**	**89.8**	**89.4**	**88.6**	**88.5**	**88.5**
Real GDP	1.8	1.8	3.0	2.8	2.3	2.2	4.2	*3.2*	**2.8**	**2.4**	**2.4**	**2.2**	**1.9**	**1.8**
GDP Price Index	2.3	2.0	1.2	2.2	2.5	2.0	3.0	*2.2*	**2.3**	**2.3**	**2.3**	**2.2**	**2.2**	**2.2**
Consumer Price Index	2.7	3.0	0.1	2.1	3.3	3.5	1.7	*2.2*	**2.4**	**2.4**	**2.2**	**2.3**	**2.3**	**2.3**

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; LIBOR quotes from Intercontinental Exchange. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).). **Interest rate data for Q3 2018 based on historical data through the week ended September 21.* *Data for Q3 2018 Major Currency Index based on data through week ended September 21. Figures for Q3 2018 Real GDP, GDP Chained Price Index and Consumer Price Index are consensus forecasts based on a special question asked of the panelists this month.*









3-Month Interest Rates[1]

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	2.39	2.31	1.33	**2.63**	**2.87**	**2.92**
Japan	-0.04	-0.03	-0.04	**-0.01**	**-0.04**	**-0.03**
U.K.	0.80	0.80	0.33	**0.90**	**1.11**	**1.30**
Switzerland	-0.73	-0.73	-0.73	**-0.75**	**-0.78**	**-0.83**
Canada	1.93	1.92	1.37	**1.86**	**2.02**	**2.29**
Australia	2.14	2.10	1.91	**2.05**	**2.22**	**2.28**
Eurozone	-0.32	-0.32	-0.33	**-0.32**	**-0.32**	**-0.16**

10-Yr. Government Bond Yields[2]

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	3.06	2.89	2.31	**3.09**	**3.19**	**3.20**
Germany	0.51	0.40	0.47	**0.62**	**0.73**	**0.96**
Japan	0.08	0.06	0.04	**0.11**	**0.11**	**0.11**
U.K.	1.58	1.46	1.41	**1.59**	**1.73**	**1.88**
France	0.85	0.74	0.76	**0.89**	**1.02**	**1.29**
Italy	2.91	3.14	2.21	**2.89**	**2.94**	**3.19**
Switzerland	0.13	-0.03	0.01	**0.08**	**0.12**	**0.25**
Canada	2.42	2.32	2.13	**2.56**	**2.70**	**2.81**
Australia	2.73	2.55	2.79	**2.67**	**2.75**	**2.80**
Spain	1.48	1.41	1.57	**1.61**	**1.76**	**2.11**

Foreign Exchange Rates[3]

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	89.52	89.75	88.12	**90.7**	**89.2**	**86.8**
Japan	112.62	111.80	112.76	**111.1**	**110.0**	**109.1**
U.K.	1.31	1.30	1.34	**1.32**	**1.32**	**1.36**
Switzerland	0.96	0.97	0.97	**0.99**	**0.99**	**0.98**
Canada	1.29	1.29	1.24	**1.29**	**1.30**	**1.25**
Australia	0.73	0.73	0.79	**0.72**	**0.71**	**0.73**
Euro	1.17	1.17	1.17	**1.18**	**1.20**	**1.25**

Consensus 3-Month Rates vs. U.S. Rate

	Now	In 12 Mo.
Japan	-2.43	**-2.95**
U.K.	-1.58	**-1.62**
Switzerland	-3.12	**-3.75**
Canada	-0.46	**-0.62**
Australia	-0.45	**-0.63**
Eurozone	-2.71	**-3.08**

Consensus 10-Year Gov't Yields vs. U.S. Yield

	Now	In 12
Germany	-2.55	**-2.24**
Japan	-2.93	**-3.09**
U.K.	-1.48	**-1.32**
France	-2.21	**-1.91**
Italy	-0.15	**-0.01**
Switzerland	-2.93	**-2.95**
Canada	-0.64	**-0.39**
Australia	-0.33	**-0.40**
Spain	-1.58	**-1.09**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Three month rate on interest-earning money market deposits denominated in selected currencies. [2]Government bonds are yields to maturity. [3]Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's Major Currency Index.

International Commentary The threat of a US-China trade war has mostly superseded EM concerns as the factor most affecting global financial markets over the past month. Equity prices worldwide appear to be the most sensitive to the ups and downs of trade tensions between these two countries. Emerging economy central banks have responded en masse to the potential for disruptive capital flight by raising their policy interest rates. Over the past two months, central banks in Argentina, Czech Republic, Indonesia, India, the Philippines, Russia, Turkey, Ukraine, and Uzbekistan have raised their policy interest rates, which at least on the margin, appears to have eased some of the tension previously being experienced by financial markets.

As expected, there was no change in policy at the **Bank of England's** September meeting. The Bank continued to note that an ongoing tightening of monetary policy over the forecast period would be needed to return inflation to the 2% target, but that rate increases would likely be at a "gradual pace and to a limited extent." Providing further support for future rate increases: the Bank slightly raised its near-term outlook for the real economy and continues to think that GDP will grow slightly faster than the economy's potential rate in the near term. Moreover, CPI inflation in August surprised to the upside, moving even further away from the 2% target. Going forward, the Bank considers the economy's primary challenge to be the implications of Brexit. The official date for Britain's exit from the EU is March 29, 2019. The recent rejection by the EU of the British government's Brexit proposal raises the specter of a "hard" Brexit and may restrain further upward adjustments to monetary policy.

The **European Central Bank** also left policy unchanged as expected in September. It repeated that the Governing Council believes it will leave its key interest rate unchanged at least through the summer of 2019 and continued its promise to do so "for as long as necessary to ensure the continued sustained convergence of inflation to levels that are below, but close to, 2% over the medium term." It also reiterated its planned phase out of its Quantitative Easing program, with the pace of monthly asset purchases reduced by half in October and expected to conclude at the end of December. It intends to maintain the value of its asset holdings by reinvesting the principal payments from maturing securities for an extended (though unspecified) period after the end of asset purchases. The ECB slightly lowered its outlook for real GDP growth for 2018 and 2019 but the Council did not appear to be concerned with the sharp slowdown in GDP growth that has already occurred. Indeed, it expects no meaningful pickup in quarterly GDP growth until the first quarter of 2019, another sign that it is in no hurry to begin to normalize policy.

The **Bank of Canada** kept its official overnight interest rate target at 1.50% at its September meeting, as was widely expected. But with headline inflation well above the 2% target, core inflation measures gradually moving above target, and the official interest rate arguably well below neutral, the market is widely expecting a rate hike at the October 25 meeting. Indeed, at the September meeting the Bank noted that "higher interest rates will be warranted to achieve the inflation target," a comment repeated by Governor Poloz in a late-September speech. However, mounting uncertainty around the renegotiation of NAFTA continues to cloud the outlook for the near-term course for Canadian monetary policy.

For the **Bank of Japan**, there was no change in policy at the mid-September meeting. Indeed, policy is likely to be on hold for the foreseeable future. As BoJ Governor Kuroda noted in early September, "There is no thought of raising rates for quite some time." The BoJ wants to push inflation up to 2%. Though the real economy appears to be reviving further in Q3 after the unexpected decline in Q1, the Bank is having almost no success in achieving its inflation target as headline inflation wallows below 1% and core inflation near zero. It has promised not to make policy less accommodative until inflation is 2%.

Sandy Batten (Haver Analytics, NY, NY)

Fourth Quarter 2018

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.
	Federal Funds Rate	Prime Bank Rate	LIBOR Rate 3-Mo.	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Major Currency $ Index	Real GDP	GDP Price Index	Cons. Price Index
Scotiabank Group	2.5 H	5.5 H	na	na	2.5 H	na	na	2.8	3.0	3.1	3.2	na	na	na	na	na	2.5	2.6	na
Barclays	2.4	5.5 H	na	na	na	na	na	3.0	3.0	3.0	3.2	na	na	na	na	na	3.0	2.2	2.3
BNP Paribas Americas	2.4	na	2.6	na	na	na	na	3.0	3.1	3.0	3.2	na	na	na	na	na	2.5	na	2.5
Goldman Sachs & Co.	2.4	na	2.7	na	2.3	na	na	3.0	3.1	3.1	3.1	na	na	na	4.8	na	3.0	2.4	2.8
J.P. Morgan Chase	2.4	na	2.6	na	na	na	na	3.0	3.1	3.2	3.2	na	na	na	na	na	2.5	2.4	2.7
Mizuho Research Institute	2.4	na	na	na	na	na	na	na	na	3.1	na	na	na	na	na	na	2.6	na	na
Swiss Re	2.4	5.4	2.5	2.3	2.2	2.4	2.5	2.6	2.7	2.9	3.4	4.7	5.6	na	4.8	na	2.4	1.4 L	2.2
TS Lombard	2.4	5.4	2.7	2.5 H	2.5 H	2.5	2.7	2.9	3.0	3.1	3.2	4.0	4.8 L	3.7	4.6	95.0 H	2.8	3.1 H	2.3
ACIMA Private Wealth	2.3	5.3	2.6	2.5 H	2.3	2.4	2.4 L	2.5 L	2.6 L	2.7 L	2.9 L	4.0	4.9	3.9	4.3 L	88.0	2.1 L	2.1	1.8
Action Economics	2.3	5.3	2.4	2.4	2.3	2.5	2.7	2.8	3.0	3.1	3.2	4.2	5.2	4.0	4.7	90.0	3.2	2.4	2.5
Moody's Analytics	2.3	5.4	2.7	2.3	2.2	2.3 L	2.5	2.7	3.0	3.2	3.7 H	4.8 H	5.7 H	3.8	4.8	na	3.4	2.7	2.4
Nomura Securities, Inc.	2.3	5.3	na	na	na	na	na	3.0	3.1	3.3	na	4.4	5.1	na	na	na	2.9	2.5	2.8
Societe Generale	2.3	5.3	na	na	2.4	na	na	2.8	na	3.0	3.2	na	na	na	na	na	2.3	2.0	1.6 L
Via Nova Investment Mgt.	2.3	5.3	2.7	2.3	2.4	2.6 H	2.8 H	3.1 H	3.3 H	3.4 H	3.5	4.5	5.2	4.2	5.0 H	92.0	3.0	2.1	2.1
AIG	2.2	5.3	na	na	2.4	2.5	2.7	2.9	3.1	3.1	3.2	na	4.9	na	4.8	na	2.9	2.4	2.7
Amherst Pierpont Securities	2.2	5.3	2.6	2.3	2.3	2.5	2.7	2.9	3.1	3.2	3.4	4.2	5.2	4.3 H	4.9	91.0	3.6 H	2.5	2.6
BMO Capital Markets	2.2	5.3	2.6	na	2.3	2.4	2.6	2.8	2.9	3.1	3.2	na	na	na	4.7	89.7	2.9	2.2	2.4
Chase Wealth Management	2.2	5.3	2.6	2.3	2.2	2.4	2.6	2.9	3.1	3.3	3.4	4.5	5.3	4.1	4.8	90.1	2.5	2.4	2.5
Chmura Economics & Analytics	2.2	5.3	2.6	2.2	2.2	2.4	2.6	2.8	2.9	3.0	3.3	4.1	na	na	4.8	87.6	2.7	2.3	1.8
Comerica Bank	2.2	5.3	2.5	na	2.2	2.4	2.6	2.7	2.9	2.9	3.1	na	na	na	4.6	na	3.0	2.2	2.1
Cycledata Corp.	2.2	5.3	2.5	2.2	2.2	2.3 L	2.5	2.7	2.9	3.0	3.1	4.1	5.0	3.9	4.7	88.0	3.0	2.2	2.4
Daiwa Capital Markets America	2.2	5.3	2.5	2.2	2.2	2.4	2.6	2.9	3.1	3.2	3.3	4.2	5.1	na	4.9	90.0	2.7	2.1	2.2
DePrince & Assoc.	2.2	5.2	2.6	2.3	2.4	2.5	2.7	2.9	2.9	3.0	3.2	4.1	na	3.9	4.7	90.4	2.6	2.0	2.1
Economist Intelligence Unit	2.2	5.2	2.5	2.3	2.4	2.4	2.6	2.9	3.0	3.1	3.2	na	na	na	4.8	na	2.2	na	2.9
Fannie Mae	2.2	5.3	na	na	2.4	2.5	2.7	2.9	3.0	3.1	3.2	na	na	na	4.7	na	2.5	2.9	2.6
GLC Financial Economics	2.2	5.2	2.5	2.2	2.3	2.5	2.6	2.8	3.0	3.1	3.3	4.4	5.1	4.0	4.9	90.5	2.8	2.2	2.5
Grant Thornton/Diane Swonk	2.2	5.3	2.8 H	2.3	2.4	2.5	2.7	2.8	2.9	3.0	3.2	3.6 L	5.0	4.0	4.7	90.8	2.7	2.6	3.0 H
High Frequency Economics	2.2	5.3	na	na	2.2	2.4	2.6	2.9	3.0	3.1	3.3	na	na	na	na	na	3.0	2.5	2.5
Loomis, Sayles & Company	2.2	5.3	2.5	2.2	2.3	2.4	2.6	2.8	3.0	3.1	3.2	4.1	4.9	3.8	4.6	90.2	3.2	2.4	2.4
MacroFin Analytics/Rutgers Bus School	2.2	5.3	2.6	2.3	2.3	2.4	2.7	2.9	3.1	3.2	3.3	4.2	5.1	3.9	4.8	91.3	2.8	2.4	2.4
Moody's Capital Markets Group	2.2	5.0 L	2.4	2.1 L	2.2	2.3 L	2.6	2.8	2.9	3.0	3.1	4.0	4.9	3.6 L	4.7	90.5	2.7	2.1	1.6 L
MUFG Union Bank	2.2	5.3	2.6	2.2	2.2	2.3 L	2.6	2.7	3.0	3.1	3.2	4.1	4.9	4.0	4.7	88.0	3.0	2.6	2.9
NatWest Markets	2.2	5.3	2.6	2.2	2.2	2.5	2.7	2.9	3.1	3.2	3.3	4.5	5.2	3.8	5.0 H	90.0	3.0	2.4	2.3
Oxford Economics	2.2	5.3	2.7	na	2.3	2.6 H	2.7	2.8	3.0	3.1	3.2	na	na	na	4.4	89.0	2.3	2.2	2.2
RDQ Economics	2.2	5.3	2.6	2.3	2.4	2.6 H	2.7	2.7	3.0	3.2	3.4	4.6	5.3	4.0	4.8	89.8	2.8	2.3	2.3
Regions Financial Corporation	2.2	5.3	2.5	2.3	2.3	2.4	2.6	2.9	3.0	3.1	3.3	4.3	5.1	4.1	4.7	89.2	2.7	2.4	1.9
S&P Global	2.2	5.0 L	2.4	na	2.4	2.6 H	2.7	2.9	3.1	3.2	3.5	na	na	na	4.8	87.4 L	3.2	2.3	2.0
The Northern Trust Company	2.2	5.3	2.7	2.3	2.4	2.5	2.6	2.8	3.0	3.2	3.4	4.2	5.1	4.1	4.8	91.6	3.4	2.5	2.5
Wells Fargo	2.2	5.2	2.3 L	2.3	2.3	2.4	2.5	2.8	3.0	3.1	3.3	3.9	4.9	4.0	4.7	90.5	2.8	2.2	2.3
Bank of America Merrill Lynch	2.1	na	2.4	na	2.2	na	na	2.8	3.1	3.2	3.2	na	na	na	na	na	3.4	2.0	2.1
Georgia State University	2.1	5.3	na	na	2.1 L	2.4	2.7	2.9	3.0	3.3	3.3	4.7	5.4	na	4.8	na	2.4	2.3	2.3
PNC Financial Services Corp.	2.1	5.3	2.5	na	2.2	2.3 L	2.5	2.8	2.9	3.0	3.2	na	5.0	4.0	4.7	88.8	3.3	2.1	2.1
Stone Harbor Investment Partners	2.1	5.2	2.5	2.3	2.2	2.3 L	2.5	2.8	2.9	3.1	3.2	4.3	5.1	na	4.7	90.0	3.0	2.2	2.3
Naroff Economic Advisors	1.9 L	5.0 L	2.4	2.1 L	2.3	2.4	2.7	3.0	3.1	3.2	3.4	4.4	5.1	3.9	4.8	89.5	2.6	2.7	2.9
October Consensus	**2.2**	**5.3**	**2.6**	**2.3**	**2.3**	**2.4**	**2.6**	**2.8**	**3.0**	**3.1**	**3.3**	**4.3**	**5.1**	**4.0**	**4.7**	**90.0**	**2.8**	**2.3**	**2.4**
Top 10 Avg.	2.4	5.4	2.7	2.4	2.4	2.5	2.7	3.0	3.1	3.3	3.4	4.6	5.3	4.1	4.9	91.4	3.3	2.7	2.8
Bottom 10 Avg.	2.1	5.2	2.4	2.2	2.2	2.3	2.5	2.7	2.9	3.0	3.1	4.0	4.9	3.8	4.6	88.5	2.4	2.0	1.9
September Consensus	2.2	5.3	2.6	2.3	2.3	2.4	2.6	2.8	3.0	3.1	3.3	4.3	5.1	4.0	4.7	89.9	2.8	2.3	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	3	4	9	5	4	5	2	6	5	8	6	5	3	5	7	11	9	6	11
Same	32	29	18	17	24	23	28	22	25	23	25	15	16	11	16	9	27	22	17
Up	7	5	7	3	10	5	3	14	10	11	9	6	7	5	11	5	6	11	13
Diffusion Index	55%	51%	47%	46%	58%	50%	52%	60%	56%	54%	54%	52%	58%	50%	56%	38%	46%	56%	52%

First Quarter 2019

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter															Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)		
	Short-Term							Intermediate-Term		Long-Term									
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.
	Federal Funds Rate	Prime Bank Rate	LIBOR Rate 3-Mo.	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Major Currency $ Index	Real GDP	GDP Price Index	Cons. Price Index
Moody's Analytics	2.7 H	5.8 H	3.2 H	2.7	2.5	2.6	2.8	2.9	3.2	3.3	4.0 H	5.0 H	5.9 H	4.0	4.9	na	2.5	2.9	2.6
Barclays	2.6	5.8 H	na	na	na	na	na	3.1	3.1	3.0	3.2	na	na	na	na	na	2.5	2.4	2.6
BNP Paribas Americas	2.6	na	2.8	na	na	na	na	3.0	3.2	3.1	na	na	na	na	na	na	1.0 L	na	2.3
Goldman Sachs & Co.	2.6	na	2.9	na	2.5	na	na	3.2	3.2	3.2	3.2	na	na	na	4.9	na	2.5	2.3	2.5
J.P. Morgan Chase	2.6	na	2.9	na	na	na	na	3.1	3.2	3.3	3.3	na	na	na	na	na	2.3	2.2	2.3
TS Lombard	2.6	5.6	2.9	2.7	2.8 H	2.8 H	3.0 H	3.0	3.2	3.5	3.6	4.4	5.3	3.9	5.0	90.0	2.4	3.3 H	2.5
ACIMA Private Wealth	2.5	5.5	2.7	2.8 H	2.4	2.5	2.4 L	2.5 L	2.4 L	2.5 L	2.9 L	4.3	5.2	4.0	4.5 L	88.0	1.8	2.3	1.5 L
Action Economics	2.5	5.6	2.7	2.6	2.6	2.7	2.8	2.9	3.0	3.2	3.3	4.3	5.2	4.1	4.8	90.0	2.8	2.1	2.6
AIG	2.5	5.6	na	na	2.5	2.8 H	2.9	3.1	3.2	3.2	3.3	na	5.0	na	4.9	na	2.6	2.5	2.4
Amherst Pierpont Securities	2.5	5.6	2.8	2.5	2.5	2.7	2.9	3.1	3.3	3.5	3.7	4.6	5.5	4.6 H	5.2	91.5	2.9	2.5	3.0
BMO Capital Markets	2.5	5.6	2.8	na	2.5	2.6	2.7	2.9	3.0	3.1	3.3	na	na	na	4.8	89.3	2.6	2.4	2.6
Comerica Bank	2.5	5.6	2.7	na	2.4	2.6	2.7	2.9	3.0	3.1	3.3	na	na	na	4.7	na	2.9	2.0	2.1
Daiwa Capital Markets America	2.5	5.6	2.8	2.4	2.5	2.6	2.8	3.1	3.3	3.4	3.5	4.4	5.3	na	5.2	91.0	2.6	2.2	2.3
DePrince & Assoc.	2.5	5.5	2.8	2.6	2.6	2.7	2.9	3.1	3.1	3.2	3.3	4.5	4.7 L	4.1	4.9	90.6	2.7	2.1	2.2
Economist Intelligence Unit	2.5	5.5	2.7	2.5	2.6	2.6	2.8	3.1	3.2	3.2	3.4	na	na	na	4.9	na	2.0	na	3.0
Grant Thornton/Diane Swonk	2.5	5.6	3.0	2.4	2.5	2.8 H	2.9	3.1	3.1	3.1	3.3	3.8 L	5.1	4.1	4.8	90.9	2.0	2.4	3.3 H
Loomis, Sayles & Company	2.5	5.5	2.8	2.4	2.5	2.7	2.8	2.9	3.1	3.2	3.2	4.2	5.0	3.9	4.7	90.2	3.0	2.6	2.6
MacroFin Analytics/Rutgers Bus School	2.5	5.6	2.8	2.5	2.6	2.7	2.9	3.2	3.3	3.4	3.6	4.4	5.3	4.1	5.1	91.7	2.3	2.4	2.2
MUFG Union Bank	2.5	5.5	2.8	2.4	2.4	2.5	2.9	2.8	3.1	3.2	3.3	4.2	5.0	4.1	4.8	87.0	2.7	2.5	3.2
Nomura Securities, Inc.	2.5	5.5	na	na	na	na	na	3.1	3.3	3.4	na	4.5	5.2	na	na	na	2.2	2.5	2.5
Scotiabank Group	2.5	5.5	na	na	2.5	na	na	2.8	3.0	3.1	3.3	na	na	na	na	na	2.1	2.5	na
Societe Generale	2.5	5.5	na	na	2.6	na	na	2.8	na	3.0	3.1	na	na	na	na	na	1.7	1.9	1.8
Swiss Re	2.5	5.5	2.6	2.4	2.4	2.5	2.6	2.8	2.7	2.9	3.5	4.7	5.6	na	4.8	na	1.9	1.7 L	3.2
Via Nova Investment Mgt.	2.5	5.5	2.9	2.5	2.6	2.8 H	3.0 H	3.3 H	3.5 H	3.6 H	3.8	4.7	5.4	4.4	5.2	93.0 H	2.5	2.2	2.2
Bank of America Merrill Lynch	2.4	na	2.7	na	2.4	na	na	2.9	3.2	3.3	3.3	na	na	na	na	na	3.0	2.2	2.3
Chase Wealth Management	2.4	5.5	2.8	2.5	2.4	2.6	2.8	3.0	3.2	3.4	3.5	4.7	5.4	4.2	4.9	90.2	1.6	2.2	2.3
Chmura Economics & Analytics	2.4	5.5	2.8	2.5	2.5	2.6	2.8	3.0	3.2	3.2	3.4	4.2	na	na	5.0	88.3	2.8	2.1	2.3
Fannie Mae	2.4	5.5	na	na	2.6	2.7	2.9	3.0	3.0	3.1	3.2	na	na	na	4.8	na	2.2	2.4	3.0
High Frequency Economics	2.4	5.5	na	na	2.5	2.6	2.8	3.1	3.1	3.2	3.4	na	na	na	na	na	2.6	2.7	2.7
Mizuho Research Institute	2.4	na	na	na	na	na	na	na	na	3.1	na	na	na	na	na	na	2.7	na	na
Moody's Capital Markets Group	2.4	5.5	2.6	2.5	2.5	2.6	2.7	2.7	2.8	2.9	3.0	4.0	4.8	3.5 L	4.6	91.0	2.5	2.1	1.8
NatWest Markets	2.4	5.5	2.8	2.5	2.5	2.7	2.9	3.0	3.3	3.3	3.5	4.6	5.3	4.1	5.1	89.0	2.8	2.6	2.7
Oxford Economics	2.4	5.3	2.9	na	2.6	2.7	2.8	2.9	3.0	3.1	3.3	na	na	na	4.9	88.1	1.8	1.9	2.2
RDQ Economics	2.4	5.5	2.8	2.5	2.6	2.8 H	2.9	2.9	3.2	3.4	3.6	4.9	5.5	4.3	5.0	90.7	2.3	2.3	2.3
Regions Financial Corporation	2.4	5.5	2.6	2.5	2.4	2.6	2.8	3.0	3.1	3.2	3.4	4.4	5.2	4.2	4.8	89.4	2.4	2.5	2.0
S&P Global	2.4	5.2 L	2.7	na	2.5	2.8 H	2.8	3.0	3.1	3.3	3.6	na	na	na	5.0	86.6 L	2.2	2.3	1.9
The Northern Trust Company	2.4	5.5	2.9	2.5	2.6	2.6	2.7	2.9	3.1	3.3	3.6	4.4	5.3	4.3	4.9	90.7	2.7	2.3	2.3
Wells Fargo	2.4	5.4	2.5 L	2.5	2.5	2.6	2.7	3.0	3.2	3.3	3.5	4.1	5.1	4.2	4.9	90.0	2.6	2.7	2.2
Cycledata Corp.	2.3	5.3	2.7	2.4	2.4	2.5	2.7	2.9	3.1	3.2	3.3	4.3	5.1	4.0	4.8	88.0	2.8	2.2	2.3
Georgia State University	2.3	5.5	na	na	2.2 L	2.7	2.9	3.0	3.2	3.4	3.6	4.8	5.6	na	5.1	na	2.2	2.2	2.0
GLC Financial Economics	2.3	5.3	2.7	2.4	2.4	2.6	2.7	2.9	3.3	3.5	3.6	4.8	5.4	4.4	5.3 H	90.0	2.6	2.1	2.8
Naroff Economic Advisors	2.2	5.3	2.6	2.3 L	2.6	2.8 H	2.9	3.2	3.3	3.4	3.6	4.7	5.3	4.1	5.0	89.0	3.3 H	2.5	2.5
PNC Financial Services Corp.	2.2	5.3	2.7	na	2.3	2.4 L	2.6	2.9	3.0	3.2	3.4	na	5.1	4.0	4.8	88.8	3.0	2.2	2.3
Stone Harbor Investment Partners	2.1 L	5.3	2.5 L	2.3 L	2.3	2.4 L	2.5	2.7	3.0	3.2	3.3	4.4	5.2	na	4.8	91.0	2.6	2.5	2.5
October Consensus	**2.4**	**5.5**	**2.8**	**2.5**	**2.5**	**2.6**	**2.8**	**3.0**	**3.1**	**3.2**	**3.4**	**4.5**	**5.3**	**4.1**	**4.9**	**89.8**	**2.4**	**2.3**	**2.4**
Top 10 Avg.	2.6	5.6	2.9	2.6	2.6	2.8	2.9	3.2	3.3	3.5	3.7	4.8	5.5	4.3	5.1	91.2	2.9	2.7	3.0
Bottom 10 Avg.	2.3	5.3	2.6	2.4	2.4	2.5	2.6	2.8	2.9	3.0	3.2	4.2	5.0	4.0	4.7	88.2	1.8	2.0	2.0
September Consensus	2.4	5.5	2.8	2.5	2.5	2.6	2.8	2.9	3.1	3.2	3.4	4.5	5.3	4.1	4.9	89.8	2.4	2.3	2.4
Number of Forecasts Changed From A Month Ago:																			
Down	3	3	10	5	2	6	8	6	6	10	6	6	7	4	6	9	7	10	6
Same	34	30	18	16	29	23	20	28	21	20	25	14	15	11	18	9	27	20	29
Up	5	5	6	4	7	4	5	8	13	12	9	6	5	6	10	7	8	9	6
Diffusion Index	52%	53%	44%	48%	57%	47%	45%	52%	59%	52%	54%	50%	46%	55%	56%	46%	51%	49%	50%

Second Quarter 2019

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
	Percent Per Annum -- Average For Quarter: Short-Term (1–7)							Intermediate-Term (8–10)			Long-Term (11–15)					Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)		
Barclays	2.9 H	6.0	na	na	na	na	na	3.2	3.1	3.0	3.1	na	na	na	na	na	2.5	2.2	2.0
Goldman Sachs & Co.	2.9 H	na	3.2	na	2.8	na	na	3.4 H	3.4	3.3	3.3	na	na	na	5.0	na	2.2	2.1	2.2
J.P. Morgan Chase	2.9 H	na	3.2	na	na	na	na	3.3	3.3	3.4	3.4	na	na	na	na	na	2.0	2.2	2.3
Moody's Analytics	2.9 H	6.1 H	3.4 H	2.9	2.8	2.8	3.0	3.1	3.3	3.5	4.1 H	5.1	6.0 H	4.1	4.9	na	2.3	2.8	2.5
TS Lombard	2.9 H	5.9	3.2	3.0 H	3.0 H	3.0 H	3.2 H	3.1	3.2	3.5	3.6	4.6	5.8	3.9	5.0	85.0 L	2.8	3.5 H	3.0
Action Economics	2.8	5.8	2.9	2.9	2.8	2.8	2.9	3.0	3.1	3.3	3.4	4.3	5.3	4.1	4.8	90.3	3.0	2.7	2.6
DePrince & Assoc.	2.8	5.8	3.2	2.9	2.9	3.0 H	3.2 H	3.3	3.3	3.4	3.5	4.8	5.4	4.4	5.1	90.8	2.8	2.2	2.4
Scotiabank Group	2.8	5.8	na	na	2.7	na	na	2.9	3.1	3.2	3.4	na	na	na	na	na	2.1	2.4	na
AIG	2.7	5.8	na	na	2.6	3.0 H	3.1	3.3	3.3	3.3	3.4	na	5.0	na	4.9	na	2.4	2.3	2.5
Amherst Pierpont Securities	2.7	5.8	3.1	2.8	2.8	2.9	3.1	3.3	3.5	3.7 H	3.9	4.8	5.8	4.8 H	5.4 H	92.0	3.1	2.5	3.0
BMO Capital Markets	2.7	5.8	3.0	na	2.6	2.7	2.9	3.0	3.1	3.2	3.3	na	na	na	4.9	88.3	2.2	1.8 L	1.7
Chmura Economics & Analytics	2.7	5.8	3.0	2.8	2.7	2.9	3.1	3.2	3.3	3.4	3.6	4.5	na	na	5.1	88.7	3.2 H	1.9	2.1
Comerica Bank	2.7	5.8	2.9	na	2.6	2.8	2.9	3.1	3.3	3.3	3.5	na	na	na	4.9	na	2.7	2.0	2.0
Daiwa Capital Markets America	2.7	5.8	3.0	2.7	2.7	2.9	3.1	3.4 H	3.5	3.6	3.7	4.6	5.5	na	5.3	92.0	2.5	2.2	2.3
Economist Intelligence Unit	2.7	5.7	3.0	2.7	2.8	2.9	2.9	3.2	3.3	3.4	3.5	na	na	na	5.0	na	3.2 H	na	2.8
Grant Thornton/Diane Swonk	2.7	5.7	3.1	2.5 L	2.6	2.9	3.1	3.2	3.2	3.2	3.4	3.8 L	5.1	4.2	4.9	91.4	2.1	2.2	2.0
High Frequency Economics	2.7	5.8	na	na	2.7	2.9	3.1	3.2	3.3	3.3	3.5	na	na	na	na	na	2.5	2.7	2.7
MacroFin Analytics/Rutgers Bus School	2.7	5.8	3.1	2.7	2.8	2.9	3.1	3.4 H	3.6 H	3.7 H	3.8	4.7	5.5	4.4	5.3	91.9	2.6	2.1	2.2
MUFG Union Bank	2.7	5.8	3.0	2.7	2.7	2.8	3.2 H	3.0	3.2	3.3	3.4	4.3	5.1	4.2	4.9	86.0	2.9	2.9	3.1 H
RDQ Economics	2.7	5.8	3.1	2.8	2.8	3.0 H	3.1	3.1	3.4	3.6	3.8	5.2 H	5.8	4.6	5.3	90.9	2.1	2.3	2.3
Regions Financial Corporation	2.7	5.8	2.7 L	2.7	2.5	2.7	2.9	3.1	3.2	3.3	3.5	4.5	5.4	4.3	4.9	89.8	2.3	2.4	2.1
Societe Generale	2.7	5.8	na	na	2.8	na	na	2.9	na	3.0	3.1	na	na	na	na	na	1.2 L	1.8 L	1.9
The Northern Trust Company	2.7	5.8	3.1	2.8	2.8	2.8	2.9	3.1	3.3	3.5	3.8	4.7	5.6	4.5	5.1	89.7	2.3	2.3	2.3
Wells Fargo	2.7	5.7	2.8	2.8	2.8	2.9	3.0	3.1	3.3	3.5	3.7	4.3	5.2	4.3	5.1	89.0	2.9	2.6	2.4
Bank of America Merrill Lynch	2.6	na	2.9	na	2.6	na	na	3.0	3.2	3.3	3.3	na	na	na	na	na	2.6	2.0	1.7
BNP Paribas Americas	2.6	na	2.8	na	na	na	na	3.0	3.2	3.2	na	na	na	na	na	na	1.5	na	1.3
Chase Wealth Management	2.6	5.6	3.0	2.7	2.6	2.7	3.0	3.1	3.3	3.5	3.6	4.8	5.6	4.4	5.1	90.1	2.0	2.0	2.1
Cycledata Corp.	2.6	5.6	2.9	2.6	2.6	2.7	2.9	3.1	3.3	3.4	3.5	4.5	5.3	4.2	5.0	88.0	2.6	2.2	2.2
Fannie Mae	2.6	5.8	na	na	2.8	2.9	3.0	3.0	3.1	3.1	3.2	na	na	na	4.8	na	2.6	2.5	2.1
Loomis, Sayles & Company	2.6	5.7	3.0	2.7	2.7	2.8	2.9	3.0	3.1	3.2	3.2	4.2	5.1	3.9	4.7	90.2	2.7	2.2	2.3
Moody's Capital Markets Group	2.6	5.8	2.8	2.5 L	2.7	2.8	2.7	2.7	2.8	2.9	3.0	4.0	4.8 L	3.5 L	4.6	91.5	2.7	2.0	1.6
NatWest Markets	2.6	5.7	3.0	2.7	2.7	2.9	3.1	3.2	3.3	3.3	3.5	4.7	5.4	4.1	5.2	88.0	2.7	1.9	0.9 L
Oxford Economics	2.6	5.5	3.0	na	2.7	2.9	2.9	3.0	3.1	3.2	3.4	na	na	na	5.0	87.4	2.0	1.9	1.9
Swiss Re	2.6	5.6	2.8	2.6	2.5	2.6	2.7	2.9	2.8	2.9	3.6	4.7	5.6	na	4.8	na	1.7	2.9	1.1
ACIMA Private Wealth	2.5	5.5	2.8	3.0 H	2.3 L	2.5 L	2.3 L	2.5 L	2.5 L	2.4 L	2.9 L	4.4	5.5	4.1	4.5 L	87.0	1.8	2.1	1.9
GLC Financial Economics	2.5	5.5	2.8	2.5 L	2.6	2.7	2.8	3.0	3.4	3.6	3.8	5.1	5.8	4.5	5.4 H	89.0	2.3	2.4	2.3
Naroff Economic Advisors	2.5	5.5	2.8	2.6	2.8	3.0 H	3.2 H	3.4 H	3.5	3.7 H	3.9	4.9	5.6	4.3	5.2	88.2	2.6	2.5	2.7
Nomura Securities, Inc.	2.5	5.5	na	na	na	na	na	3.1	3.1	3.3	na	4.4	5.1	na	na	na	1.8	2.6	1.4
S&P Global	2.5	5.4 L	3.0	na	2.5	2.8	2.8	3.0	3.1	3.3	3.7	na	na	na	5.1	85.8	1.9	2.3	2.0
Via Nova Investment Mgt.	2.5	5.5	2.9	2.5 L	2.6	2.8	3.0	3.3	3.5	3.6	3.8	4.7	5.4	4.4	5.2	94.0 H	2.5	2.2	2.2
Georgia State University	2.4 L	5.5	na	na	2.3 L	2.7	2.8	3.1	3.3	3.6	3.9	5.1	5.9	na	5.2	na	2.2	2.3	1.9
Mizuho Research Institute	2.4 L	na	na	na	na	na	na	na	na	3.0	na	na	na	na	na	na	2.5	na	na
PNC Financial Services Corp.	2.4 L	5.5	2.9	na	2.5	2.6	2.7	2.9	3.0	3.2	3.5	na	5.2	3.9	4.9	88.9	2.7	2.4	2.4
Stone Harbor Investment Partners	2.4 L	5.5	2.7 L	2.5 L	2.5	2.6	2.7	2.8	3.2	3.3	3.4	4.5	5.3	na	4.9	89.0	2.1	2.5	2.3
October Consensus	**2.7**	**5.7**	**3.0**	**2.7**	**2.7**	**2.8**	**3.0**	**3.1**	**3.2**	**3.3**	**3.5**	**4.6**	**5.4**	**4.2**	**5.0**	**89.4**	**2.4**	**2.3**	**2.2**
Top 10 Avg.	2.8	5.9	3.2	2.9	2.8	3.0	3.1	3.3	3.4	3.6	3.9	4.9	5.8	4.5	5.3	91.5	2.9	2.8	2.7
Bottom 10 Avg.	2.5	5.5	2.8	2.6	2.5	2.7	2.7	2.9	3.0	3.0	3.2	4.3	5.1	4.0	4.8	87.2	1.8	1.9	1.5
September Consensus	2.6	5.7	3.0	2.7	2.6	2.8	2.9	3.1	3.2	3.3	3.5	4.6	5.4	4.2	5.0	89.6	2.4	2.3	0.0
Number of Forecasts Changed From A Month Ago:																			
Down	5	4	6	5	5	4	5	6	4	8	8	5	5	5	8	9	5	11	11
Same	30	30	21	13	24	21	20	25	24	25	23	15	16	10	15	9	29	25	23
Up	7	4	7	7	9	8	8	11	12	9	9	6	6	6	11	7	8	3	7
Diffusion Index	52%	50%	51%	54%	55%	56%	55%	56%	60%	51%	51%	52%	52%	52%	54%	46%	54%	40%	45%

Third Quarter 2019

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.
	Federal Funds Rate	Prime Bank Rate	LIBOR Rate 3-Mo.	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Major Currency $ Index	Real GDP	GDP Price Index	Cons. Price Index
Moody's Analytics	3.3 H	6.4 H	3.6 H	3.2 H	3.0	3.1	3.3	3.3	3.4	3.5	4.3 H	5.1	6.1	4.1	5.0	na	1.8	2.6	2.3
Barclays	3.1	6.3	na	na	na	na	na	3.3	3.1	3.0	3.1	na	na	na	na	na	2.0	2.4	2.3
Goldman Sachs & Co.	3.1	na	3.4	na	3.0	na	na	3.5	3.5	3.3	3.3	na	na	na	5.1	na	1.8	2.1	2.2
J.P. Morgan Chase	3.1	na	3.3	na	na	na	na	3.4	3.5	3.5	3.4	na	na	na	na	na	1.8	2.3	2.4
TS Lombard	3.1	6.1	3.4	3.2 H	3.3 H	3.3 H	3.5 H	3.1	3.1	3.0	3.0	4.3	6.3 H	3.3 L	4.5 L	75.0 L	2.2	3.7 H	3.5 H
MUFG Union Bank	3.0	6.0	3.2	2.9	3.0	3.1	3.4	3.2	3.3	3.4	3.5	4.4	5.2	4.3	5.0	84.0	2.8	2.1	3.0
Action Economics	2.9	6.0	3.2	3.0	2.9	2.9	3.0	3.1	3.2	3.4	3.5	4.4	5.3	4.1	4.9	90.3	2.7	2.2	2.5
AIG	2.9	5.9	na	na	2.8	3.2	3.3	3.4	3.4	3.4	3.5	na	5.1	na	5.0	na	2.0	2.3	2.2
Amherst Pierpont Securities	2.9	6.1	3.3	3.0	3.0	3.1	3.3	3.4	3.7	3.8	4.1	5.0	6.0	5.0 H	5.5 H	92.5	3.0	2.6	3.1
Bank of America Merrill Lynch	2.9	na	3.2	na	2.8	na	na	3.1	3.3	3.4	3.4	na	na	na	na	na	2.4	2.1	2.5
BMO Capital Markets	2.9	6.0	3.1	na	2.7	2.8	2.9	3.1	3.1	3.2	3.4	na	na	na	4.9	87.2	2.0	1.9	1.9
Chmura Economics & Analytics	2.9	6.0	3.2	3.0	2.9	3.1	3.3	3.5	3.6	3.6	3.8	4.7	na	na	5.2	88.9	3.6 H	1.9	2.0
Comerica Bank	2.9	6.0	3.2	na	2.9	3.1	3.2	3.4	3.6	3.6	3.8	na	na	na	5.2	na	2.6	1.9	2.0
Daiwa Capital Markets America	2.9	6.0	3.2	2.9	2.9	3.1	3.3	3.6 H	3.7	3.7	3.8	4.8	5.7	na	5.5 H	93.0 H	2.4	2.3	2.4
DePrince & Assoc.	2.9	5.9	3.4	3.1	3.0	3.1	3.4	3.5	3.4	3.5	3.6	5.1	5.7	4.6	5.2	91.0	2.6	2.2	2.4
Economist Intelligence Unit	2.9	5.9	3.1	2.9	3.0	3.1	3.2	3.3	3.4	3.5	3.6	na	na	na	5.1	na	2.2	na	2.9
High Frequency Economics	2.9	6.0	na	na	3.0	3.1	3.2	3.3	3.4	3.5	3.7	na	na	na	na	na	2.1	2.8	2.8
MacroFin Analytics/Rutgers Bus School	2.9	6.0	3.3	2.9	3.0	3.1	3.3	3.6 H	3.7	3.8	4.0	4.9	5.7	4.6	5.5 H	92.2	2.4	2.2	2.1
Oxford Economics	2.9	5.6	3.1	na	2.9	3.0	3.1	3.1	3.1	3.2	3.4	na	na	na	5.2	86.8	2.0	1.7 L	1.8
RDQ Economics	2.9	6.0	3.3	3.0	3.0	3.1	3.2	3.3	3.6	3.8	4.0	5.5 H	6.1	4.8	5.5 H	91.4	2.3	2.4	2.4
Regions Financial Corporation	2.9	6.0	2.8	2.8	2.6	2.8	2.9	3.2	3.3	3.4	3.6	4.6	5.5	4.4	5.1	89.5	1.9	2.3	2.1
Societe Generale	2.9	6.0	na	na	2.9	na	na	2.9	na	2.8	2.9	na	na	na	na	na	0.0 L	1.7 L	1.7
Swiss Re	2.9	5.9	3.0	2.8	2.7	2.9	3.0	3.1	2.9	3.0	3.7	4.7	5.6	na	4.8	na	1.6	1.8	2.0
The Northern Trust Company	2.9	6.0	3.2	3.0	2.9	2.9	3.0	3.2	3.4	3.7	4.0	5.0	5.9	4.7	5.3	88.9	2.0	2.2	2.2
Wells Fargo	2.9	5.9	3.0	3.0	3.0	3.1	3.2	3.2	3.4	3.6	3.8	4.4	5.3	4.4	5.2	87.8	2.6	2.6	2.6
Chase Wealth Management	2.8	5.8	3.2	2.7	2.9	2.9	3.1	3.2	3.4	3.5	3.7	4.8	5.6	4.4	5.2	90.0	2.1	2.1	2.2
Nomura Securities, Inc.	2.8	5.8	na	na	na	na	na	3.1	3.1	3.2	na	4.3	5.0	na	na	na	1.8	2.5	2.5
Scotiabank Group	2.8	5.8	na	na	2.8	na	na	3.0	3.1	3.2	3.4	na	na	na	na	na	2.0	2.3	na
Via Nova Investment Mgt.	2.8	5.8	3.1	2.7	2.7	2.9	3.0	3.3	3.5	3.7	3.8	4.8	5.5	4.6	5.3	93.0 H	2.5	2.2	2.3
Grant Thornton/Diane Swonk	2.7	5.8	3.2	2.6	2.6	3.0	3.1	3.2	3.2	3.3	3.4	3.8 L	5.2	4.2	5.0	91.5	2.0	2.3	1.5 L
Loomis, Sayles & Company	2.7	5.8	3.0	2.8	2.8	2.8	2.9	3.1	3.1	3.2	3.2	4.2	5.1	3.9	4.7	90.2	2.4	2.3	2.3
Naroff Economic Advisors	2.7	5.8	3.0	2.7	3.0	3.1	3.4	3.6 H	3.8 H	3.9 H	4.1	5.1	5.7	4.5	5.5 H	87.5	2.2	2.3	2.3
NatWest Markets	2.7	5.8	3.1	2.7	2.7	2.9	3.0	3.3	3.3	3.4	3.6	4.8	5.5	4.1	5.2	88.0	2.6	1.8	1.7
S&P Global	2.7	5.5	3.1	na	2.7	2.9	3.0	3.1	3.2	3.4	3.8	na	na	na	5.1	85.6	2.1	2.4	3.0
BNP Paribas Americas	2.6	na	2.7	na	na	na	na	2.9	3.1	3.1	na	na	na	na	na	na	1.4	na	2.3
Cycledata Corp.	2.6	5.6	2.9	2.6	2.6	2.7	2.9	3.1	3.3	3.4	3.5	4.5	5.3	4.2	5.0	88.0	2.6	2.2	2.2
Fannie Mae	2.6	5.8	na	na	2.9	3.0	3.1	3.0	3.1	3.1	3.3	na	na	na	4.8	na	2.4	2.0	na
Georgia State University	2.6	5.8	na	na	2.4	2.9	3.0	3.3	3.4	3.9 H	4.2	5.2	6.1	na	5.5 H	na	2.1	2.2	1.9
GLC Financial Economics	2.6	5.6	2.8	2.6	2.6	2.7	2.8	3.0	3.4	3.7	3.9	5.3	6.0	4.6	5.5 H	88.8	2.9	2.5	2.1
Moody's Capital Markets Group	2.6	5.8	2.8	2.6	2.6	2.7	2.7	2.6	2.7	2.8	2.9	3.9	4.8 L	3.4	4.5 L	91.0	1.7	2.0	1.8
PNC Financial Services Corp.	2.6	5.8	3.0	na	2.7	2.7	2.8	3.0	3.0	3.2	3.5	na	5.2	3.8	4.9	88.9	2.3	2.4	2.4
Mizuho Research Institute	2.4	na	na	na	na	na	na	na	na	3.0	na	na	na	na	na	na	2.3	na	na
Stone Harbor Investment Partners	2.4	5.5	2.7	2.5 L	2.4	2.5	2.6	2.7	3.1	3.2	na	4.4	5.2	na	4.8	87.0	1.9	2.1	2.7
ACIMA Private Wealth	2.2 L	5.2 L	2.6 L	2.8	2.0 L	2.2 L	2.2 L	2.3 L	2.3 L	2.2 L	2.8 L	4.2	5.3	4.0	4.6	85.0	1.8	2.0	1.9
October Consensus	**2.8**	**5.9**	**3.1**	**2.8**	**2.8**	**2.9**	**3.1**	**3.2**	**3.3**	**3.4**	**3.6**	**4.7**	**5.5**	**4.3**	**5.1**	**88.6**	**2.2**	**2.2**	**2.3**
Top 10 Avg.	3.0	6.1	3.3	3.0	3.0	3.1	3.4	3.5	3.6	3.8	4.0	5.1	6.0	4.6	5.4	91.6	2.8	2.7	2.9
Bottom 10 Avg.	2.5	5.6	2.8	2.7	2.5	2.7	2.8	2.9	3.0	2.9	3.1	4.2	5.1	3.9	4.7	85.4	1.6	1.9	1.8
September Consensus	2.8	5.9	3.1	2.8	2.8	2.9	3.0	3.1	3.3	3.4	3.6	4.7	5.5	4.3	5.1	89.2	2.1	2.2	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	5	5	6	6	6	5	5	2	6	7	6	6	8	5	6	8	1	10	11
Same	31	29	18	14	20	22	19	27	22	25	22	16	12	11	19	10	32	26	21
Up	6	4	8	5	11	6	9	10	9	7	8	4	7	5	9	7	9	3	8
Diffusion Index	51%	49%	53%	48%	57%	52%	56%	60%	54%	50%	53%	46%	48%	50%	54%	48%	60%	41%	46%

Fourth Quarter 2019

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.
	Federal Funds Rate	Prime Bank Rate	LIBOR Rate 3-Mo.	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Major Currency $ Index	Real GDP	GDP Price Index	Cons. Price Index
Moody's Analytics	3.5 H	6.6 H	3.8 H	3.4 H	3.2	3.2	3.4	3.4	3.5	3.6	4.3	5.2	6.2	4.1	5.1	na	1.1	2.3	2.1
Barclays	3.4	6.5	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.5	2.4	2.2
Goldman Sachs & Co.	3.4	na	3.7	na	3.3	na	na	3.6	3.5	3.4	3.4	na	na	na	5.2	na	1.6	2.1	2.1
J.P. Morgan Chase	3.4	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.5	2.3	2.4
Chmura Economics & Analytics	3.2	6.3	3.5	3.3	3.2	3.3	3.5 H	3.7	3.8	3.8	3.9	4.9	na	na	5.4	88.6	3.6 H	2.1	2.3
Economist Intelligence Unit	3.2	6.2	3.3	3.1	3.2	3.3	3.4	3.4	3.5	3.6	3.8	na	na	na	5.2	na	1.8	na	2.4
High Frequency Economics	3.2	6.3	na	na	3.2	3.3	3.3	3.4	3.5	3.6	3.8	na	na	na	na	na	2.0	2.9	2.9
RDQ Economics	3.2	6.3	3.7	3.3	3.4 H	3.5 H	3.5 H	3.5	3.7	3.9	4.1	5.7 H	6.2	4.9	5.6	91.4	2.2	2.4	2.4
Regions Financial Corporation	3.2	6.3	2.8	2.9	2.8	2.9	3.0	3.3	3.4	3.5	3.7	4.7	5.6	4.5	5.2	89.2	1.6	2.2	2.0
Amherst Pierpont Securities	3.1	6.3	3.5	3.2	3.2	3.3	3.5 H	3.6	3.8	4.0	4.3	5.2	6.2	5.1 H	5.7 H	93.0	2.7	2.7	3.2
Bank of America Merrill Lynch	3.1	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.1	2.1	2.5
Comerica Bank	3.1	6.2	3.4	na	3.1	3.3	3.4	3.6	3.7	3.8	4.0	na	na	na	5.4	na	2.2	2.0	2.0
DePrince & Assoc.	3.1	6.1	3.5	3.3	3.2	3.3	3.5 H	3.6	3.6	3.6	3.8	5.3	6.0	4.8	5.4	91.2	2.5	2.2	2.4
Wells Fargo	3.1	6.1	3.2	3.2	3.1	3.2	3.2	3.2	3.4	3.6	3.9	4.5	5.4	4.5	5.2	86.3	2.4	2.4	2.7
Chase Wealth Management	3.0	6.0	3.3	3.0	3.1	3.1	3.2	3.3	3.5	3.5	3.7	4.9	5.6	4.5	5.2	89.9	1.9	2.0	2.1
Daiwa Capital Markets America	3.0	6.1	3.3	2.9	3.0	3.1	3.3	3.7	3.8	3.8	3.9	5.0	5.9	na	5.7 H	94.0 H	2.2	2.3	2.5
MUFG Union Bank	3.0	6.0	3.2	2.9	3.0	3.1	3.4	3.2	3.3	3.4	3.5	4.4	5.2	4.3	5.0	84.0	2.7	2.1	3.1
Scotiabank Group	3.0	6.0	na	na	3.0	na	na	3.1	3.2	3.3	3.5	na	na	na	na	na	2.0	2.3	na
Swiss Re	3.0	6.0	3.1	2.9	2.8	3.0	3.1	3.2	3.0	3.0	3.8	4.7	5.7	na	4.9	na	1.6	1.4 L	2.2
Via Nova Investment Mgt.	3.0	6.0	3.3	3.0	2.9	3.1	3.3	3.5	3.8	3.9	4.0	5.1	5.7	4.9	5.5	92.0	2.5	2.3	2.3
Action Economics	2.9	6.0	3.2	3.1	3.0	3.1	3.1	3.1	3.3	3.4	3.5	4.4	5.4	4.1	4.9	90.3	2.4	2.4	2.5
AIG	2.9	6.0	na	na	2.8	3.2	3.4	3.5	3.4	3.4	3.5	na	5.1	na	5.1	na	1.8	2.3	2.0
BMO Capital Markets	2.9	6.0	3.1	na	2.7	2.8	2.9	3.0	3.1	3.2	3.4	na	na	na	5.0	86.0	1.8	2.0	2.1
Loomis, Sayles & Company	2.9	6.0	3.2	3.0	2.9	3.0	3.0	3.1	3.1	3.2	3.2	4.2	5.1	3.9	4.7	90.2	2.2	2.3	2.3
MacroFin Analytics/Rutgers Bus School	2.9	6.0	3.3	3.0	3.0	3.2	3.4	3.6	3.8	3.9	4.0	4.9	5.8	4.6	5.5	92.4	2.4	2.2	2.1
Naroff Economic Advisors	2.9	6.0	3.2	3.0	3.2	3.3	3.5 H	3.8 H	3.9 H	4.0	4.3	5.3	6.0	4.8	5.6	86.8	1.1	2.1	1.5 L
NatWest Markets	2.9	6.0	3.2	2.9	2.9	3.1	3.2	3.2	3.2	3.3	3.5	4.8	5.5	4.1	5.2	87.0	2.5	1.8	1.5 L
Oxford Economics	2.9	5.8	3.2	na	3.0	3.1	3.2	3.2	3.2	3.3	3.5	na	na	na	5.1	86.2	1.7	1.7	1.9
S&P Global	2.9	5.5	3.1	na	2.9	3.0	3.1	3.1	3.3	3.4	3.8	na	na	na	5.2	85.5	2.2	2.2	2.3
Societe Generale	2.9	6.0	na	na	2.9	na	na	2.8	na	2.6	2.8	na	na	na	na	na	-1.4 L	1.7	2.5
The Northern Trust Company	2.9	6.0	3.2	3.0	2.9	2.9	3.0	3.2	3.4	3.7	4.0	5.2	5.9	4.7	5.3	88.3	1.7	2.2	2.2
Nomura Securities, Inc.	2.8	5.8	na	na	na	na	na	3.0	3.0	3.1	na	4.2	4.9 L	na	na	na	1.9	2.5	2.7
PNC Financial Services Corp.	2.8	5.8	3.0	na	2.7	2.7	2.8	2.9	3.0	3.2	3.4	na	5.1	3.8	4.8	89.0	2.0	2.4	2.4
Georgia State University	2.7	5.8	na	na	2.5	3.0	3.1	3.5	3.7	4.1 H	4.5 H	5.5	6.3 H	na	5.7 H	na	2.1	2.1	2.1
GLC Financial Economics	2.7	5.7	2.9	2.7	2.7	2.8	2.9	3.1	3.6	3.9	4.1	5.5	6.3 H	4.8	5.7 H	88.2	2.1	2.6	2.4
Grant Thornton/Diane Swonk	2.7	5.8	3.1	2.5	2.6	3.0	3.1	3.1	3.2	3.3	3.5	3.7 L	5.2	4.2	5.0	92.3	1.9	2.3	2.1
BNP Paribas Americas	2.6	na	2.6	na	na	na	na	2.6	2.9	3.0	na	na	na	na	na	na	1.3	na	2.6
Cycledata Corp.	2.6	5.6	2.9	2.6	2.6	2.7	2.9	3.1	3.3	3.4	3.5	4.5	5.3	4.2	5.0	88.0	2.6	2.2	2.2
Fannie Mae	2.6	5.8	na	na	3.0	3.0	3.1	3.0	3.1	3.2	3.3	na	na	na	4.8	na	2.1	2.5	2.2
Moody's Capital Markets Group	2.6	5.8	2.9	2.6	2.6	2.6	2.6	2.6	2.7	2.8	2.9	4.0	4.9 L	3.4	4.5	89.0	1.9	2.0	1.8
Mizuho Research Institute	2.4	na	na	na	na	na	na	na	na	2.9	na	na	na	na	na	na	1.9	na	na
Stone Harbor Investment Partners	2.4	5.5	2.7	2.5	2.4	2.4	2.5	2.6	3.0	3.1	3.2	4.3	5.1	na	4.7	85.0	1.5	2.9	2.5
TS Lombard	2.4	5.4	2.5	2.3 L	2.3	2.2	2.2	2.3	2.5	2.8	2.8	4.1	6.1	3.1 L	4.3 L	80.0 L	2.0	3.7 H	3.5 H
ACIMA Private Wealth	1.8 L	4.8 L	2.3 L	2.6	1.6 L	1.8 L	1.8 L	2.0 L	2.1 L	2.0 L	2.6 L	3.9	5.1	3.7	4.4	85.0	1.5	1.9	1.8
October Consensus	**2.9**	**6.0**	**3.2**	**2.9**	**2.9**	**3.0**	**3.1**	**3.2**	**3.3**	**3.4**	**3.7**	**4.7**	**5.6**	**4.3**	**5.1**	**88.5**	**1.9**	**2.3**	**2.3**
Top 10 Avg.	3.3	6.3	3.5	3.2	3.2	3.3	3.5	3.6	3.8	3.9	4.2	5.3	6.1	4.8	5.6	91.7	2.6	2.7	2.8
Bottom 10 Avg.	2.5	5.6	2.8	2.7	2.5	2.6	2.7	2.7	2.8	2.9	3.1	4.2	5.1	3.9	4.7	85.2	1.1	1.9	1.9
September Consensus	2.9	6.0	3.2	2.9	2.9	3.0	3.1	3.2	3.3	3.4	3.7	4.8	5.6	4.4	5.1	88.9	1.9	2.2	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	3	4	9	5	5	5	4	4	4	5	7	6	5	6	8	8	5	7	7
Same	33	30	16	15	22	21	21	25	24	25	22	14	15	9	16	10	30	25	26
Up	6	4	7	5	10	7	8	10	9	9	8	6	7	6	10	7	7	7	8
Diffusion Index	54%	50%	47%	50%	57%	53%	56%	58%	57%	55%	51%	50%	54%	50%	53%	48%	52%	50%	51%

First Quarter 2020

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term				Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Moody's Analytics	3.6 H	6.7 H	3.9 H	3.6 H	3.3	3.3	3.5	3.5	3.5	3.6	4.3	5.2	6.3	4.2	5.1	na	0.5	1.5 L	1.8
Chmura Economics & Analytics	3.4	6.5	3.7	3.5	3.4 H	3.6 H	3.7	3.9	4.0	4.0	4.1	5.1	na	na	5.5	87.9	2.1	1.8	1.9
Goldman Sachs & Co.	3.4	na	3.7	na	3.3	na	na	3.6	3.5	3.4	3.4	na	na	na	5.2	na	1.5	2.2	2.2
DePrince & Assoc.	3.3	6.3	3.7	3.5	3.4 H	3.5	3.7	3.8	3.7	3.8	3.9	5.7 H	6.5 H	5.2	5.5	91.4	2.3	2.3	2.4
AIG	3.2	6.3	na	na	3.0	3.4	3.4	3.5	3.4	3.4	3.6	na	5.1	na	5.1	na	1.8	2.4	2.1
Amherst Pierpont Securities	3.2	6.3	3.5	3.2	3.2	3.4	3.5	3.7	3.9	4.1	4.4	5.3	6.4	5.3 H	5.8	93.0	2.5	2.8	3.3
Chase Wealth Management	3.2	6.2	3.5	3.2	3.3	3.4	3.4	3.5	3.6	3.6	3.8	5.1	5.8	4.6	5.3	89.5	1.5	1.9	2.0
Daiwa Capital Markets America	3.2	6.3	3.5	3.1	3.2	3.3	3.5	3.9	3.9	3.9	3.9	5.1	6.1	na	5.9	95.0 H	2.0	2.3	2.5
Economist Intelligence Unit	3.2	6.2	3.3	3.1	3.2	3.3	3.4	3.4	3.5	3.6	3.8	na	na	na	5.2	na	0.0 L	na	2.2
Regions Financial Corporation	3.2	6.3	2.8	2.8	2.7	2.8	2.9	3.2	3.3	3.4	3.6	4.6	5.5	4.4	5.1	88.8	1.8	2.0	2.1
Action Economics	3.1	6.2	3.3	3.2	3.1	3.1	3.2	3.3	3.3	3.4	3.5	4.4	5.4	4.1	4.9	90.2	2.4	2.1	2.5
Bank of America Merrill Lynch	3.1	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.1	2.2	2.6
Comerica Bank	3.1	6.2	3.4	na	3.1	3.3	3.4	3.6	3.7	3.8	4.0	na	na	na	5.4	na	1.7	2.0	2.0
MacroFin Analytics/Rutgers Bus School	3.1	6.2	3.5	3.1	3.2	3.3	3.5	3.8	4.0	4.1	4.3	5.1	5.9	4.8	5.7	92.6	2.2	2.2	2.1
Naroff Economic Advisors	3.1	6.3	3.4	3.1	3.4 H	3.6 H	3.8 H	4.0 H	4.1 H	4.3 H	4.5	5.5	6.2	5.0	5.8	85.0	0.5	1.9	1.7
Oxford Economics	3.1	5.8	3.2	na	3.1	3.2	3.2	3.3	3.3	3.3	3.6	na	na	na	5.3	85.8	1.4	1.7	1.9
S&P Global	3.1	5.9	3.4	na	3.1	3.2	3.3	3.3	3.3	3.5	3.9	na	na	na	5.3	85.6	1.3	2.1	2.1
Wells Fargo	3.1	6.1	3.2	3.2	3.0	3.1	3.1	3.2	3.4	3.6	3.9	4.5	5.4	4.4	5.2	85.8	2.2	2.2	2.6
BMO Capital Markets	3.0	6.1	3.2	na	2.8	2.9	3.0	3.1	3.2	3.3	3.5	na	na	na	5.0	85.2	1.5	2.1	2.1
MUFG Union Bank	3.0	6.0	3.2	2.9	3.0	3.1	3.4	3.2	3.3	3.4	3.5	4.4	5.2	4.3	5.0	84.0 L	2.7	2.1	3.1
Via Nova Investment Mgt.	3.0	6.0	3.3	3.0	2.8	3.0	3.1	3.3	4.0	3.8	3.8	5.1	5.6	4.8	5.4	91.0	2.5	2.3	2.3
Georgia State University	2.9	6.0	na	na	2.6	3.1	3.2	3.5	3.9	4.2	4.6 H	5.5	6.4	na	5.8	na	2.0	2.2	2.2
Loomis, Sayles & Company	2.9	6.0	3.2	3.0	2.9	3.0	3.0	3.1	3.1	3.2	3.2	4.2	5.1	3.9	4.7	90.2	2.0	2.4	2.3
NatWest Markets	2.9	6.0	3.1	2.9	2.9	3.0	3.1	3.1	3.2	3.3	3.4	4.8	5.5	4.0	5.1	86.0	1.9	2.2	2.2
Societe Generale	2.9	6.0	na	na	2.8	na	na	2.5	na	2.5	2.7	na	na	na	na	na	na	na	na
The Northern Trust Company	2.9	6.0	3.2	3.0	2.9	2.9	3.0	3.2	3.4	3.7	4.0	5.2	5.9	4.7	5.3	87.8	1.5	2.2	2.2
GLC Financial Economics	2.8	5.8	3.0	2.9	2.9	3.0	3.1	3.3	3.7	4.0	4.2	5.6	6.3	5.1	6.1 H	87.9	2.4	2.4	2.4
Nomura Securities, Inc.	2.8	5.8	na	na	na	na	na	3.0	3.0	3.1	na	4.2	4.9 L	na	na	na	1.7	2.5	2.7
PNC Financial Services Corp.	2.8	5.8	3.0	na	2.7	2.7	2.8	2.9	3.0	3.2	3.4	na	5.1	3.7	4.8	89.1	1.7	2.4	2.4
Cycledata Corp.	2.6	5.6	2.9	2.6	2.6	2.7	2.9	3.1	3.3	3.4	3.5	4.5	5.3	4.2	5.0	88.0	2.6	2.2	2.2
Fannie Mae	2.6	5.8	na	na	3.0	3.1	3.1	3.0	3.1	3.2	3.3	na	na	na	4.8	na	1.4	2.2	2.8
Moody's Capital Markets Group	2.6	5.8	2.9	2.6	2.6	2.6	2.5	2.5	2.6	2.7	2.8	4.0	4.9 L	3.3	4.5	88.5	2.8 H	1.9	1.6 L
Grant Thornton/Diane Swonk	2.5	5.6	3.1	2.4	2.4	2.8	3.0	3.1	3.2	3.3	3.5	3.8	5.2	4.1	5.0	91.5	1.7	2.7	3.6 H
Mizuho Research Institute	2.4	na	na	na	na	na	na	na	na	2.9	na	na	na	na	na	na	na	na	na
Stone Harbor Investment Partners	2.1	5.2	2.4	2.2	2.0	2.0	2.1	2.2	2.8	2.9	3.1	4.1	4.9 L	na	4.5	85.0	1.4	3.0 H	2.8
TS Lombard	1.6	4.6	1.7 L	1.5 L	1.6	1.4 L	1.2 L	1.5 L	1.8	2.0	2.3 L	3.6 L	5.1	2.6 L	3.5 L	90.0	1.8	3.0 H	2.5
ACIMA Private Wealth	1.3 L	4.3 L	2.0	2.0	1.2 L	1.4 L	1.4	1.6	1.6 L	1.6 L	2.4	3.9	5.1	3.5	4.2	85.0	1.0	2.0	1.6 L
October Consensus	**2.9**	**5.9**	**3.2**	**2.9**	**2.9**	**3.0**	**3.1**	**3.2**	**3.3**	**3.4**	**3.6**	**4.7**	**5.6**	**4.3**	**5.2**	**88.5**	**1.8**	**2.2**	**2.3**
Top 10 Avg.	3.3	6.3	3.6	3.3	3.3	3.4	3.5	3.7	3.9	4.0	4.2	5.3	6.2	4.8	5.7	91.4	2.5	2.6	2.9
Bottom 10 Avg.	2.3	5.4	2.7	2.5	2.3	2.4	2.5	2.5	2.7	2.7	3.0	4.1	5.1	3.8	4.6	85.5	1.1	1.9	1.9
September Consensus	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na
Number of Forecasts Changed From A Month Ago:																			
Down	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na
Same	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na
Up	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na
Diffusion Index	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na

International Interest Rate And Foreign Exchange Rate Forecasts

United States

	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			Fed's Major Currency $ Index		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	3.00	3.00	na	na	na	na
BMO Capital Markets	na	na	na	3.10	3.15	3.25	89.5	89.1	86.5
IHSMarkit	na	na	na	3.05	3.16	3.34	na	na	na
ING Financial Markets	2.75	3.00	3.25	3.20	3.30	3.20	93.7	91.8	86.0
Mizuho Research Institute	2.40	2.40	2.35	3.10	3.10	3.00	87.0	86.0	86.0
Moody's Analytics	2.70	3.13	3.58	3.18	3.34	3.54	na	na	na
Moody's Capital Markets	na	na	na	2.95	2.90	2.85	91.0	91.0	91.4
Nomura Securities	na	na	na	na	na	na	na	na	na
Oxford Economics	na	na	na	3.10	3.14	3.24	88.1	87.4	86.2
Scotiabank	na	na	na	3.05	3.10	3.20	na	na	na
TS Lombard	2.68	2.93	2.48	3.10	3.50	2.80	95.0	90.0	85.0
Wells Fargo	na	na	na	3.20	3.35	3.55	na	na	na
October Consensus	**2.63**	**2.87**	**2.92**	**3.09**	**3.19**	**3.20**	**90.7**	**89.2**	**86.8**
High	2.75	3.13	3.58	3.20	3.50	3.55	95.0	91.8	91.4
Low	2.40	2.40	2.35	2.95	2.90	2.80	87.0	86.0	85.0
Last Months Avg.	2.72	2.90	3.19	3.04	3.13	3.25	89.8	89.6	88.5

Japan

	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/YEN		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	0.15	0.15	na	112.0	110.0	na
BMO Capital Markets	na	na	na	0.10	0.11	0.12	110.0	110.0	108.0
IHSMarkit	na	na	na	na	na	na	112.3	113.5	116.8
ING Financial Markets	-0.05	-0.05	0.00	0.10	0.10	0.10	108.0	108.0	102.0
Mizuho Research Institute	0.05	0.05	0.05	0.10	0.10	0.10	109.0	108.0	108.0
Moody's Analytics	0.08	0.08	0.07	0.03	0.01	0.00	112.5	112.8	113.1
Moody's Capital Markets	na	na	na	0.12	0.15	0.15	114.5	114.7	115.0
Nomura Securities	na	na	na	na	na	na	110.0	110.0	110.0
Oxford Economics	na	na	na	0.10	0.10	0.10	108.3	108.3	108.4
Scotiabank	na	na	na	na	na	na	110.0	110.0	108.0
TS Lombard	-0.10	-0.25	-0.25	0.10	0.10	0.05	115.0	105.0	102.0
Wells Fargo	na	na	na	0.16	0.20	0.24	na	na	na
October Consensus	**-0.01**	**-0.04**	**-0.03**	**0.11**	**0.11**	**0.11**	**111.1**	**110.0**	**109.1**
High	0.08	0.08	0.07	0.16	0.20	0.24	115.0	114.7	116.8
Low	-0.10	-0.25	-0.25	0.03	0.01	0.00	108.0	105.0	102.0
Last Months Avg.	0.03	0.03	0.03	0.09	0.10	0.10	110.5	110.4	110.0

United Kingdom

	3 Mo. Interest Rate %			10 Yr. Gilt Yields %			GBP/USD		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	1.60	1.65	na	1.32	1.31	na
BMO Capital Markets	na	na	na	1.65	1.70	1.85	1.25	1.23	1.34
IHSMarkit	na	na	na	na	na	na	1.29	1.28	1.30
ING Financial Markets	0.80	0.85	1.05	1.50	1.55	1.80	1.33	1.36	1.49
Mizuho Research Institute	0.85	0.85	1.10	1.70	1.75	1.90	na	na	na
Moody's Analytics	0.94	0.94	1.13	1.63	1.74	2.07	1.31	1.30	1.35
Moody's Capital Markets	na	na	na	1.65	1.70	1.65	1.31	1.30	1.30
Nomura Securities	na	na	na	na	na	na	1.44	1.48	1.56
Oxford Economics	na	na	na	1.40	1.55	1.85	1.36	1.37	1.40
Scotiabank	na	na	na	na	na	na	1.32	1.32	1.37
TS Lombard	1.00	1.80	1.90	1.65	2.35	2.00	1.30	1.25	1.15
Wells Fargo	na	na	na	1.50	1.60	1.90	na	na	na
October Consensus	**0.90**	**1.11**	**1.30**	**1.59**	**1.73**	**1.88**	**1.32**	**1.32**	**1.36**
High	1.00	1.80	1.90	1.70	2.35	2.07	1.44	1.48	1.56
Low	0.80	0.85	1.05	1.40	1.55	1.65	1.25	1.23	1.15
Last Months Avg.	0.89	0.93	1.17	1.56	1.68	1.90	1.33	1.35	1.40

Switzerland

	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/CHF		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	na	na	na	0.97	0.97	na
BMO Capital Markets	na	na	na	na	na	na	1.02	1.01	1.00
IHSMarkit	na	na	na	na	na	na	0.99	1.00	1.01
ING Financial Markets	-0.65	-0.65	-0.65	0.05	0.05	0.25	0.98	0.98	0.97
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Moody's Analytics	-0.81	-0.79	-0.74	0.06	0.15	0.37	1.04	1.06	1.02
Moody's Capital Markets	na	na	na	0.05	0.07	0.08	0.98	0.99	0.99
Nomura Securities	na	na	na	na	na	na	0.96	0.94	0.89
Oxford Economics	na	na	na	0.15	0.27	0.48	0.98	0.97	0.94
Scotiabank	na	na	na	na	na	na	na	na	na
TS Lombard	-0.80	-0.90	-1.10	0.07	0.06	0.05	0.98	1.00	1.00
Wells Fargo	na	na	na	na	na	na	na	na	na
October Consensus	**-0.75**	**-0.78**	**-0.83**	**0.08**	**0.12**	**0.25**	**0.99**	**0.99**	**0.98**
High	-0.65	-0.65	-0.65	0.15	0.27	0.48	1.04	1.06	1.02
Low	-0.81	-0.90	-1.10	0.05	0.05	0.05	0.96	0.94	0.89
Last Months Avg.	-0.73	-0.73	-0.70	0.12	0.21	0.34	0.99	0.99	0.97

Canada

	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/CAD		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	na	na	na	1.30	1.30	na
BMO Capital Markets	na	na	na	2.55	2.63	2.79	1.28	1.27	1.25
IHSMarkit	na	na	na	na	na	na	1.28	1.28	1.28
ING Financial Markets	2.00	2.00	2.40	2.70	2.80	3.00	1.28	1.25	1.20
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Moody's Analytics	1.99	2.17	2.68	3.02	3.31	3.58	1.28	1.26	1.24
Moody's Capital Markets	na	na	na	2.40	2.35	2.33	1.31	1.32	1.33
Nomura Securities	na	na	na	na	na	na	1.33	1.35	1.35
Oxford Economics	na	na	na	2.59	2.79	3.14	1.29	1.28	1.28
Scotiabank	na	na	na	2.45	2.60	2.70	1.28	1.25	1.22
TS Lombard	1.60	1.90	1.80	2.40	2.60	2.20	1.30	1.40	1.10
Wells Fargo	na	na	na	2.40	2.50	2.70	na	na	na
October Consensus	**1.86**	**2.02**	**2.29**	**2.56**	**2.70**	**2.81**	**1.29**	**1.30**	**1.25**
High	2.00	2.17	2.68	3.02	3.31	3.58	1.33	1.40	1.35
Low	1.60	1.90	1.80	2.40	2.35	2.20	1.28	1.25	1.10
Last Months Avg.	2.07	2.14	2.67	2.60	2.76	2.94	1.29	1.28	1.27

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

Blue Chip Forecasters	3 Mo. Interest Rate % In 3 Mo.	In 6 Mo.	In 12 Mo.	10 Yr. Gov't Bond Yield % In 3 Mo.	In 6 Mo.	In 12 Mo.	AUD/USD In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	na	na	na	0.70	0.70	na
BMO Capital Markets	na	na	na	na	na	na	0.70	0.71	0.73
IHSMarkit	na	na	na	na	na	na	0.70	0.69	0.69
ING Financial Markets	2.00	2.00	2.00	2.70	2.70	2.80	0.70	0.72	0.85
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Moody's Analytics	1.85	1.85	1.85	2.53	2.50	2.51	0.72	0.71	0.70
Moody's Capital Markets	na	na	na	2.70	2.70	2.65	0.72	0.72	0.71
Nomura Securities	na	na	na	na	na	na	0.74	0.74	0.72
Oxford Economics	na	na	na	2.61	2.75	3.02	0.74	0.75	0.76
Scotiabank	na	na	na	na	na	na	0.73	0.75	0.77
TS Lombard	2.30	2.80	3.00	2.80	3.10	3.00	0.75	0.65	0.60
Wells Fargo	na	na	na	na	na	na	na	na	na
October Consensus	**2.05**	**2.22**	**2.28**	**2.67**	**2.75**	**2.80**	**0.72**	**0.71**	**0.73**
High	2.30	2.80	3.00	2.80	3.10	3.02	0.75	0.75	0.85
Low	1.85	1.85	1.85	2.53	2.50	2.51	0.70	0.65	0.60
Last Months Avg.	1.97	1.99	2.07	2.76	2.80	2.89	0.74	0.75	0.75

Euro area

Blue Chip Forecasters	3 Mo. Interest Rate % In 3 Mo.	In 6 Mo.	In 12 Mo.	EUR/USD In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	1.15	1.15	na
BMO Capital Markets	na	na	na	1.18	1.19	1.24
IHSMarkit	na	na	na	1.13	1.12	1.10
ING Financial Markets	-0.32	-0.32	-0.12	1.17	1.20	1.28
Mizuho Research Institute	-0.30	-0.30	-0.25	1.20	1.21	1.23
Moody's Analytics	-0.33	-0.33	-0.27	1.13	1.11	1.15
Moody's Capital Markets	na	na	na	1.16	1.16	1.45
Nomura Securities	na	na	na	1.25	1.30	1.40
Oxford Economics	na	na	na	1.21	1.22	1.25
Scotiabank	na	na	na	1.20	1.22	1.25
TS Lombard	-0.32	-0.32	0.00	1.16	1.30	1.10
Wells Fargo	na	na	na	na	na	na
October Consensus	**-0.32**	**-0.32**	**-0.16**	**1.18**	**1.20**	**1.25**
High	-0.30	-0.30	0.00	1.25	1.30	1.45
Low	-0.33	-0.33	-0.27	1.13	1.11	1.10
Last Months Avg.	-0.34	-0.31	-0.17	1.18	1.19	1.23

10 Yr. Gov't Bond Yields %

Blue Chip Forecasters	Germany In 3 Mo.	In 6 Mo.	In 12 Mo.	France In 3 Mo.	In 6 Mo.	In 12 Mo.	Italy In 3 Mo.	In 6 Mo.	In 12 Mo.	Spain In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.60	0.65	na	na	na	na	na	na	na	na	na	na
BMO Capital Markets	0.70	0.75	0.95	na	na	na	na	na	na	na	na	na
ING Financial Markets	0.50	0.55	0.70	0.80	0.80	1.00	2.75	2.75	3.20	1.50	1.50	1.75
Mizuho Research Institute	0.60	0.65	0.80	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.69	0.85	1.11	0.87	0.98	1.09	2.31	2.09	2.28	1.81	1.97	2.11
Moody's Capital Markets	0.60	0.65	0.70	0.92	0.99	1.05	2.90	2.95	2.94	1.60	1.70	1.80
Nomura Securities	na	na	na	na	na	na	na	na	na	na	na	na
Oxford Economics	0.60	0.73	0.97	1.03	1.16	1.40	3.50	3.63	3.87	1.55	1.73	2.07
TS Lombard	0.65	0.95	1.55	0.85	1.15	1.90	3.00	3.30	3.65	1.60	1.90	2.80
Wells Fargo	0.60	0.75	0.90	na	na	na	na	na	na	na	na	na
October Consensus	**0.62**	**0.73**	**0.96**	**0.89**	**1.02**	**1.29**	**2.89**	**2.94**	**3.19**	**1.61**	**1.76**	**2.11**
High	0.70	0.95	1.55	1.03	1.16	1.90	3.50	3.63	3.87	1.81	1.97	2.80
Low	0.50	0.55	0.70	0.80	0.80	1.00	2.31	2.09	2.28	1.50	1.50	1.75
Last Months Avg.	0.57	0.70	0.93	0.85	0.96	1.12	2.86	2.85	2.86	1.69	1.79	1.92

Consensus Forecasts
10-year Bond Yields vs U.S. Yield

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-2.93	-2.99	-3.07	-3.09
United Kingdom	-1.48	-1.51	-1.45	-1.32
Switzerland	-2.93	-3.02	-3.07	-2.95
Canada	-0.64	-0.53	-0.49	-0.39
Australia	-0.33	-0.43	-0.44	-0.40
Germany	-2.55	-2.48	-2.46	-2.24
France	-2.21	-2.20	-2.17	-1.91
Italy	-0.15	-0.20	-0.24	-0.01
Spain	-1.58	-1.48	-1.43	-1.09

Consensus Forecasts
3 Mo. Deposit Rates vs U.S. Rate

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-2.43	-2.64	-2.82	-2.95
United Kingdom	-1.58	-1.74	-1.76	-1.62
Switzerland	-3.12	-3.39	-3.65	-3.75
Canada	-0.46	-0.77	-0.84	-0.62
Australia	-0.45	-0.58	-0.65	-0.63
Eurozone	-2.71	-2.95	-3.18	-3.08

Viewpoints:

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

Consumer Outlook in a Rising Rate Environment

Conventional wisdom has it that rising interest rates are bad for consumer spending because swelling financing costs put a squeeze on a household's capacity for other outlays. What if conventional wisdom is wrong? Our analysis finds that a rising interest rate environment does not immediately snuff out consumer spending growth. As the current expansion stretches further into its tenth year, the economy is on track to eclipse the expansion of the 1990s as the longest on record. In this report we consider the outlook for consumer spending against this backdrop of a record-setting expansion and consider how long the good times will last. Our base-case scenario, spelled out in this special report, anticipates a modest pick-up in consumer spending, at least in the near term. Eventually, like all good things, the longest economic expansion on record will come to an end and consumer spending will come back down with it. That will likely occur alongside financial conditions that warrant rate cuts by the Fed. The precise timing of these events is tough to get right, but by signaling this drop-off in activity in late 2020, we are essentially saying that while the end of the party is not imminent, no cycle lasts forever.

As we would at any time in the business cycle, we consider the macro drivers of consumer behavior. Consumer sentiment and confidence, by about any measure, are at or near high levels last seen around 2001; which, not coincidentally, was in the late stages of that prior long-lasting expansion. We also look at the purchasing power in consumers' wallets, be it in the form of personal income, which is at last picking up (albeit in only a modest way) or in access to capital through borrowing, where measures of revolving consumer credit growth indicate a leveling off more recently. Finally, we tally the actual spending numbers reflected in the personal income and spending report and the monthly retail sales numbers, both of which have been on a roll in recent months.

In an effort to better inform a consumer outlook, it is essential to have a framework for thinking about these fundamentals and how households will manage finances at this late stage of the cycle. The trouble with considering this period in the context of what has happened in prior cycles is that for a long stretch in the current cycle, from December 2008 until December 2015, the Federal Reserve maintained a near zero interest rate policy (ZIRP), and at various points during those years was engaged in a broad expansion of the balance sheet through quantitative easing (QE). The Fed has historically purchased Treasury securities to expand the monetary base, although the monetary policy "medicine" applied during that era, including the purchases of mortgage-backed securities and other assets, had not been tried before, at least not in the United States.

Central bank actions, no doubt, are a factor in the remarkable duration of the current cycle, and on that basis any informed outlook for consumer spending ought to not only consider these macro drivers (like confidence, access to capital and willingness to spend) but to consider them in the context of Fed policy. To that end, we went back to just before the 1990s expansion began in 1989 and divided the years since into four broad categories based on what the Federal Reserve was doing with monetary policy at the time: (1) lowering the fed funds rate, (2) a "stable" rate environment, (3) raising the fed funds rate and (4) ZIRP with QE. Most of the time periods are straightforward, although the one period that might invite critique is that we have characterized the time period from March of 1995 through January 2001 as "stable".

One could reasonably observe that the fed funds rate actually moved up and down during that nearly six-year stretch. Our argument for calling it "stable" is that this period was essentially from the "mid-cycle" slowdown until the end of that expansion. Admittedly, there were adjustments up and down throughout the period, but from the start of the period to the end, the funds rate finished just 50 basis points higher. Reasonable minds could disagree, but in our view, the idea of thinking of that period as four unique rate cycles would unnecessarily complicate our analysis. With our various Fed cycle dates established, we looked at our macro drivers for consumer spending through the lens of the Fed policy that was in place at the time. For each interest rate backdrop, we calculated the average levels for various measures of consumer confidence, the average annualized growth rate of personal income, the average net monthly expansion in consumer credit and finally the average annual growth rates of both real personal consumption expenditures and of nominal retail sales. A key takeaway from our exercise is that measures of consumer fundamentals tend to do best in periods of stable interest rates. Interestingly though, a rising rate environment is almost as good for these same consumer fundamentals. Perhaps that is not altogether surprising, considering that the Fed is apt to raise rates when the economy is at full employment and inflation is heating up beyond the Fed's comfort zone. Those factors tend to exist when the economy is doing particularly well or even overheating.

The inverse of that dynamic may explain why the worst rate theme for consumer spending is during periods when the Fed is lowering rates. Personal income and spending as well as nominal retail sales all performed worst during periods when the Fed was cutting rates. Interestingly, the lowering of interest rates does not compel consumers to increase their appetite for credit, at least not immediately. The average net monthly increase in consumer credit came in a distant last during periods when the Fed was actively lowering rates.

So what sort of Fed policy theme should we consider looking forward? To judge from the Fed's dotplot, a visual rendering of policymakers' own forecasts for the fed funds rate, the FOMC is closing in on its neutral rate for fed funds. With most dots clustered around 3.00 to 3.25% and the current fed funds rate at 2.00%, there are only four or five quarter-point rate hikes left to go in the current cycle, barring some change in forward guidance from the Fed. Our forecast anticipates two more hikes this year and another three next year. After that it stands to reason we would be in a stable rate environment slightly above the neutral rate until the Fed's understanding of r* changes (favoring another hike) or until conditions warrant a cut. In a separate special report, we explained our use of an analytical framework we recently developed to inform our view of Fed policy going forward and why we look for the FOMC to raise rates another 125 bps before it cuts rates at the end of 2020.

In forming our outlook for the consumer, we take the findings of our rate-environment study and overlay them with our expectations for Fed policy over the next couple of years. If things play out the way we anticipate, monetary policy is entering an era of transition unlike anything the economy has seen in more than a decade. For a number of factors including the longevity of the cycle, growing fiscal budget imbalances and a potential fallout from the global economy, we indicated in our initial 2020 forecast that by the end of our forecast horizon the Fed would likely begin cutting the fed funds rate. A rate-tightening environment is expected to prevail at least through the first part of 2019, which will be followed by a stable rate for another year or so before the Fed begins to signal eventual rate cuts.

Viewpoints

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

For the consumer, this Fed forecast implies a pick-up in the pace of consumer spending in the near term before an eventual slowing the further out we go in the forecast period. Full year PCE growth was 2.5% in 2017. By the time we close the books on the current year, we expect the comparable number for 2018 to pick up to 2.6%, prior to quickening to 2.7% in 2019 and slowing to just 2.2% in 2020.

Consumers may be better prepared to endure a slowdown than in the past. The saving rate, currently at 6.7%, is rather elevated given the late stage of expansion, while real median household income surpassed its pre-recession peak in 2017. With the unemployment rate currently matching low levels last seen in the late 1960s, there remains little slack in the economy. The labor market is expected to grow increasingly tight, with the unemployment rate trending to as low as 3.3% by 2020. Similarly, inflationary pressures that continue to gradually build over our forecast horizon will put downward pressure on real income gains. The length of the current expansion is expected to surpass that of the 1990s, taking the title as the longest expansion on record. While monetary policy changes act as signals to markets about the health of the economy and/or concerns about inflation expectations, we must be sensitive to policy movements and their implication for consumer spending. Our initial 2020 forecast expects the Fed to surpass its neutral rate, prior to beginning to cut policy by the end of 2020. With this signal of a slowdown in activity, we are essentially saying that this expansion will eventually draw to a close. The rate cutting environment will act as a last call announcement – and for the consumer sector it serves as a valuable indication for longevity of this expansion.

Tim Quinlan (Wells Fargo Securities)

Yielding Different Results

Markets have reacted very differently to deficit-financed fiscal expansion plans in the US and Italy. In the US, 10-year Treasury yields rose by nearly 40bp earlier this year following the passage of the tax bill in December 2017. We expect tax (and subsequent spending) legislation to increase the fiscal deficit to 5.5% of GDP in 2021, a level not seen since the 1980s outside of recession. By contrast, Italian government bonds have sold off sharply ahead of the release of the government's budget proposal, which will likely imply deficits below 3% of GDP, lower than that projected for the US. The spread between 10- year Italian BTPs and German bunds remains about 130bp higher than in early May, even after recent retracement.

What explains these different responses? Clearly, different starting levels of debt are one factor, with US public debt at 105% of GDP (75% if intragovernmental debt is excluded), and Italy's public debt at 133% of GDP. More importantly, we expect lower growth in Italy, so the debt trajectory looks worse when compared to the US, even at lower fiscal deficit levels. But even absolute debt-to-GDP levels aren't the determinative factor in yields. After all, Japan, with public debt at 232% of GDP (195% if certain debt is excluded) pays among the lowest rates in the developed world. To be sure, the fact that the BOJ has bought nearly 45% of government bonds outstanding has helped, as has its "Yield Curve Control" policy, which explicitly targets the 10-year yield. However, even without these factors, we suspect yields would be higher by no more than an additional 60-120bp. That is, high levels of public debt-to-GDP by themselves need not cause a death spiral between the level of government bond yields and the debt load.

While debt levels aren't the determinative factor of bond yields, they can matter for a variety of reasons. First, one could theoretically argue that substantial government debt should lead to a "crowding out" in interest rates. This presumably works by reducing the capital stock available for private investment, thereby increasing the marginal cost of capital. In practice, there has been little evidence of this occurring either in the US or Japan. Some studies have found about a 3-4bp increase in long-term US rates for a 1pp increase in debt-to-GDP ratios, but others have found no effect. Part of the reason we don't observe crowding out is that the pool of savings is actually quite large: in the case of the US, the dollar is the reserve currency, so substantial global savings are recycled into Treasuries; and in Japan, a large pool of private sector savings is able to absorb current levels of government debt while still retaining a net savings surplus.

Second, even without a crowding out effect, investor constraints—either owing to mandates or, for example, a preference to hold a certain share of short-duration assets— mean increases in supply can show up as a temporary increase in term premia. We estimate a 3bp increase in 10-year term premia per 1pp increase in the US deficit-to-GDP ratio. But we also note that these impacts are transient, dissipating once there is an offsetting inflow of funds.

Third, an increase in public debt can raise questions about the sustainability of the debt load. This could lead markets to price increased inflation and/or credit risk. For a sovereign issuing in its own currency, the key risk is the former, because the debt can in principle be monetized. Yet, in both the US and Japan, there has been no sign of markets demanding inflation compensation because of this risk. Larger central bank balance sheets have been viewed more as monetary tools, and not as an addendum to fiscal policy, particularly given that high inflation hasn't been realized in the economy.

The Italian situation is markedly different. Here, you have a monetary authority that is supranational, along with an unfavorable combination of high levels of public debt, lower growth, and political instability. While the ECB could theoretically provide a backstop, as the experience with Greek debt shows, this does not mean the risk of debt restructuring or principal losses are absent. Markets are looking to the upcoming budget proposals to gauge the risks around the path of Italian government debt and its sustainability. These proposals could generate increased friction with EU institutions and trigger potential downgrades from ratings agencies. Given that Italy is only two notches above the investment grade ratings threshold, downgrades present a challenge, as they could lead to an erosion in the investor base. In the extreme, markets could also start to worry about redenomination risk (i.e., the risk that Italy abandons the euro), though we stress this is a remote scenario. We believe many of the above risks are showing up to varying degrees in the spread between Italian and German government bonds. If the question was one of purely fiscal divergence, the spread would be lower, in our view. What's unclear is how much more premium markets will demand for some of the more unique structural constraints Italy faces. Current market behavior suggests this could be large.

Praveen Korapaty (Goldman Sachs and Co. LLC)

Special Questions:

1. Please provide your forecasts of the Q3 2018 change (q/q, saar) in real GDP, the GDP Price Index and the Consumer Price Index.

	Real GDP	GDP Price Index	Consumer Price Index
Consensus	**3.2%**	**2.2%**	**2.2%**
Top 10 Average	3.7%	2.7%	2.6%
Bottom 10 Average	2.9%	1.7%	1.9%

2. At which meeting will the FOMC NEXT raise interest rates?

(Percentage of those responding)

Nov 7-8	Dec 18-19	Jan 29-30	Mar 19-20	Later
0.0%	93.2%	2.3%	4.5%	0.0%

3. The FOMC is also quite likely to continue raising rates during 2019. How much do you believe they will raise the funds rate during that year?

Total increase in federal funds rate target in 2019:
(Percentage of those responding)

0 b.p.	25 b.p.	50 b.p.	75 b.p.	100 b.p.	More than 100 b.p.
4.5%	15.9%	25.0%	36.4%	18.2%	0.0%

4. What will be the terminal level of the fed funds rate during the Fed's current tightening cycle?

	Peak fed funds rate
Consensus	**3.2%**
Top 10 Average	4.0%
Bottom 10 Average	2.6%

4a. Is this above, below or equal to your perceived "neutral" fed funds rate?

(Percentage of those responding)

Above	Below	Equal to
48.8%	9.8%	41.5%

5. The personal consumption expenditure price index excluding food & energy is forecast by the FOMC; this index was up 1.98% year-on-year in July. What is your forecast for this index's percentage change, December-over-December?

December-over-December change in the PCE Price Index:

	2018	2019
Consensus	**2.1%**	**2.2%**
Top 10 Average	2.2%	2.5%
Bottom 10 Average	1.9%	1.9%

6. Trade negotiations, especially with China, are moving along in fits and spurts. Does the trade issue impact your GDP forecast?

(Percentage of those responding)

	No	Yes	If yes, how much
2018	56.8%	43.2%	-.030
2019	45.7%	54.3%	-.007

7. What is your forecast for the unemployment rate in December 2018? December 2019?

Unemployment rate in December:

	2018	2019
Consensus	**3.7%**	**3.6%**
Top 10 Average	3.9%	4.0%
Bottom 10 Average	3.6%	3.2%

8. The spread between 2-year Treasury notes and 10-year Treasuries has recently hovered just above 20 basis points. Do you think this key portion of the yield curve will invert by the end of this year? If not then, by the end of 2019?

(Percentage of those responding)

Invert in 2018		**Invert in 2019**	
Yes	No	Yes	No
9.5%	90.5%	23.1%	76.9%

9. What might be the probability of a recession starting in 2018? If not this year, then what about next year – or 2020?

	2018	2019	2020
Consensus	**8.7%**	**23.8%**	**32.0%**
Top 10 Average	16.6%	42.0%	56.5%
Bottom 10 Average	2.7%	11.2%	11.2%

Databank:

2018 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	-0.1	0.1	0.7	0.3	1.2	0.2	0.7	0.1				
Auto & Light Truck Sales (b)	17.12	16.92	17.23	17.20	17.20	17.23	16.70	16.60				
Personal Income (a, current $)	0.5	0.3	0.4	0.3	0.4	0.4	0.3	0.3				
Personal Consumption (a, current $)	0.2	-0.1	0.6	0.5	0.5	0.4	0.5	0.3				
Consumer Credit (e)	3.8	3.5	2.6	2.7	6.8	2.6	5.1					
Consumer Sentiment (U. of Mich.)	95.7	99.7	101.4	98.8	98.0	98.2	97.9	96.2	100.1			
Household Employment (c)	409	785	-37	3	293	102	389	-423				
Nonfarm Payroll Employment (c)	176	324	155	175	268	208	147	201				
Unemployment Rate (%)	4.1	4.1	4.1	3.9	3.8	4.0	3.9	3.9				
Average Hourly Earnings (All, cur. $)	26.71	26.74	26.80	26.86	26.94	26.99	27.06	27.16				
Average Workweek (All, hrs.)	34.4	34.5	34.5	34.5	34.5	34.6	34.5	34.5				
Industrial Production (d)	2.8	3.6	3.6	3.8	2.9	3.5	4.1	4.8				
Capacity Utilization (%)	77.0	77.2	77.5	78.2	77.4	77.8	77.9	78.1				
ISM Manufacturing Index (g)	59.1	60.8	59.3	57.3	58.7	60.2	58.1	61.3				
ISM Nonmanufacturing Index (g)	59.9	59.5	58.8	56.8	58.6	59.1	55.7	58.5				
Housing Starts (b)	1.334	1.290	1.327	1.276	1.329	1.177	1.174	1.282				
Housing Permits (b)	1.366	1.323	1.377	1.364	1.301	1.292	1.303	1.249				
New Home Sales (1-family) (h)	633	663	672	633	653	618	608	629				
Construction Expenditures (a)	0.3	2.3	-0.9	1.7	0.7	-0.8	0.1					
Consumer Price Index (nsa, d)	2.1	2.2	2.4	2.5	2.8	2.9	2.9	2.7				
CPI ex. Food and Energy (nsa, d)	1.8	1.8	2.1	2.1	2.2	2.3	2.4	2.2				
Producer Price Index (nsa, d)	2.6	2.8	2.9	2.7	3.1	3.4	3.3	2.8				
Durable Goods Orders (a)	-4.2	4.5	2.7	-1.0	-0.3	0.9	-1.2	4.5				
Leading Economic Indicators (a)	0.7	0.6	0.3	0.5	0.1	0.5	0.7	0.4				
Balance of Trade & Services (f)	-52.3	-55.0	-46.7	-45.5	-42.6	-45.7	-50.1					
Federal Funds Rate (%)	1.41	1.42	1.51	1.69	1.70	1.82	1.91	1.91				
3-Mo. Treasury Bill Rate (%)	1.43	1.59	1.73	1.79	1.90	1.94	1.99	2.07				
10-Year Treasury Note Yield (%)	2.58	2.86	2.84	2.87	2.98	2.91	2.89	2.89				

2017 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	1.2	-0.5	0.2	0.7	-0.3	0.5	0.1	0.1	1.8	0.6	0.8	0.0
Auto & Light Truck Sales (b)	17.32	17.28	16.76	16.84	16.82	16.80	16.70	16.45	18.09	17.88	17.52	17.34
Personal Income (a, current $)	0.7	0.5	0.3	0.1	0.4	0.1	0.4	0.4	0.5	0.4	0.3	0.4
Personal Consumption (a, current $)	0.4	-0.1	0.6	0.3	0.2	0.3	0.2	0.4	0.8	0.4	0.7	0.3
Consumer Credit (e)	5.3	5.8	4.1	4.1	5.7	3.6	4.7	4.3	2.6	6.4	9.6	4.1
Consumer Sentiment (U. of Mich.)	98.5	96.3	96.9	97.0	97.1	95.0	93.4	96.8	95.1	100.7	98.5	95.9
Household Employment (h)	-157	435	553	97	-269	358	261	-40	853	-478	71	104
Nonfarm Payroll Employment (c)	259	200	73	175	155	239	190	221	14	271	216	175
Unemployment Rate (%)	4.8	4.7	4.5	4.4	4.3	4.3	4.3	4.4	4.2	4.1	4.1	4.1
Average Hourly Earnings (All, cur. $)	25.99	26.07	26.11	26.17	26.21	26.26	26.34	26.39	26.51	26.47	26.54	26.64
Average Workweek (All, hrs.)	34.4	34.4	34.3	34.4	34.4	34.4	34.4	34.4	34.3	34.4	34.5	34.5
Industrial Production (d)	-0.5	-0.1	1.2	2.0	2.1	1.9	1.5	1.1	1.3	2.6	3.4	2.9
Capacity Utilization (%)	75.4	75.1	75.5	76.2	76.2	76.2	76.1	75.7	75.7	76.8	77.1	77.3
ISM Manufacturing Index (g)	55.6	57.6	56.6	55.3	55.5	56.7	56.5	59.3	60.2	58.5	58.2	59.3
ISM Nonmanufacturing Index (g)	56.8	57.4	55.6	57.3	57.1	57.2	54.3	55.2	59.4	59.8	57.3	56.0
Housing Starts (b)	1.225	1.289	1.179	1.165	1.122	1.225	1.185	1.172	1.158	1.265	1.303	1.210
Housing Permits (b)	1.329	1.248	1.279	1.255	1.205	1.312	1.258	1.300	1.254	1.343	1.323	1.320
New Home Sales (1-family) (h)	596	618	643	593	604	616	556	558	637	618	712	636
Construction Expenditures (a)	-0.3	0.9	1.2	-1.2	0.9	-1.0	0.1	-0.4	0.2	0.6	0.8	1.2
Consumer Price Index (nsa, d)	2.5	2.7	2.4	2.2	1.9	1.6	1.7	1.9	2.2	2.0	2.2	2.1
CPI ex. Food and Energy (nsa, d)	2.3	2.2	2.0	1.9	1.7	1.7	1.7	1.7	1.7	1.8	1.7	1.8
Producer Price Index (nsa, d)	1.7	2.0	2.2	2.5	2.3	1.9	2.0	2.4	2.6	2.8	3.0	2.5
Durable Goods Orders (a)	0.2	-0.9	2.9	1.4	-1.2	7.1	-7.4	2.7	4.7	-4.1	2.2	3.2
Leading Economic Indicators (a)	0.6	0.3	0.5	0.2	0.4	0.6	0.3	0.4	0.0	1.3	0.4	0.8
Balance of Trade & Services (f)	-46.9	-44.2	-43.9	-46.1	-45.8	-44.8	-44.2	-44.2	-44.4	-47.0	-49.0	-51.9
Federal Funds Rate (%)	0.65	0.66	0.79	0.90	0.91	1.04	1.15	1.16	1.15	1.15	1.16	1.30
3-Mo. Treasury Bill Rate (%)	0.52	0.53	0.75	0.81	0.90	1.00	1.09	1.03	1.05	1.09	1.25	1.34
10-Year Treasury Note Yield (%)	2.43	2.42	2.48	2.30	2.30	2.19	2.32	2.21	2.20	2.36	2.35	2.40

(a) month-over-month % change; (b) millions, saar; (c) month-over-month change, thousands; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level; (h) thousands. Most series are subject to frequent government revisions. Use with care.

Calendar of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
October 1 IHS-Markit Mfg PMI (Sep, Final) ISM Manufacturing (Sep) Construction (Aug) Vehicle Sales (Sep)	**2** CoreLogic HPI (Aug) ISM New York (Sep)	**3** IHS-Markit Services PMI (Sep, Final) ISM Nonmanufacturing (Sep) ADP Employment Report (Sep) EIA Crude Oil Stocks Mortgage Applications	**4** MSIO (Aug) Weekly Jobless Claims Weekly Money Supply Public Debt (Sep)	**5** Employment Situation (Sep) International Trade (Aug) Consumer Credit (Aug)
8	**9** Existing Home Sales (Sep) Kansas City Financial Stress Index (Sep) NFIB (Sep)	**10** Producer Prices (Sep) Wholesale Trade (Aug) Tech Pulse Index (Sep) EIA Crude Oil Stocks Mortgage Applications	**11** CPI (Sep) Cleveland Fed Median CPI (Sep) Weekly Jobless Claims Weekly Money Supply	**12** Import & Export Prices (Sep) Consumer Sentiment (Oct, Preliminary)
15 Advance Retail Sales (Sep) MTIS (Aug) Empire State Mfg Survey (Oct)	**16** IP & Capacity Utilization (Sep) JOLTS (Aug) Business Leaders Survey (Oct) Home Builders (Oct) TIC Data (Aug)	**17** New Residential Construction (Sep) Kansas City Fed Labor Market Conditions Indicators (Sep) EIA Crude Oil Stocks Mortgage Applications	**18** Philadelphia Fed Manufacturing Business Outlook Survey (Oct) Composite Indexes (Sep) Weekly Jobless Claims Weekly Money Supply	**19** Existing Home Sales (Sep)
22 Chicago Fed National Activity Index (Sep)	**23** Philadelphia Fed Nonmanufacturing Business Outlook Survey (Oct) Richmond Fed Mfg & Service Sector Surveys (Oct)	**24** IHS-Markit Flash PMI (Oct) New Residential Sales (Sep) FHFA HPI (Aug) Final Building Permits (Sep) EIA Crude Oil Stocks Mortgage Applications	**25** Adv Trade & Inventories (Sep) Advance Durable Goods (Sep) Home Mortgages (Sep) Kansas City Fed Manufacturing Survey (Oct) FRB Philadelphia Coincident Econ Activity Index (Sep) Pending Home Sales (Sep) Weekly Jobless Claims Weekly Money Supply	**26** GDP (Q3, Adv) Consumer Sentiment (Oct, Final)
29 Personal Income (Sep) Dallas Fed Trimmed-Mean PCE (Sep) Texas Manufacturing Outlook Survey (Oct)	**30** Case-Shiller HPI (Aug) Housing Vacancies (Q3) Agricultural Prices (Sep) Consumer Confidence (Oct) Texas Service Sector Outlook Survey (Oct)	**31** ADP Employment Report (Oct) Employment Cost Index (Q3) Chicago PMI (Oct) EIA Crude Oil Stocks Mortgage Applications	**November 1** Productivity & Costs (Q3) IHS-Markit Mfg PMI (Oct) ISM Manufacturing (Oct) Construction (Sep) Challenger Employment (Oct) First Time Housing Affordability (Q3) Weekly Jobless Claims Weekly Money Supply	**2** Employment Situation (Oct) International Trade (Sep) Manufacturers' Shipments, Inventories & Orders (Sep) ISM New York (Oct) l
5 IHS-Markit Services PMI (Oct) ISM Nonmanufacturing (Oct)	**6** CoreLogic HPI (Sep) JOLTS (Sep) ublic Debt (Oct)	**7** Business Employment Dynamics (Q1) Consumer Credit (Sep) Kansas City Fed Labor Market Conditions Indicators (Oct) EIA Crude Oil Stocks Mortgage Applications	8 FOMC Policy Rate Announcement (Nov) Kansas City Financial Stress Index (Oct) NAHB-Wells Fargo Housing Opportunity Index (Q3) Weekly Jobless Claims Weekly Money Supply	**9** Producer Prices (Oct) Retail E-Commerce Sales (Q3) Consumer Sentiment (Nov, Preliminary) Wholesale Trade (Sep)

BLUE CHIP FORECASTERS

CONTRIBUTORS TO DOMESTIC SURVEY

Action Economics, LLC, Boulder, CO
Michael Englund
AIG, New York, NY
Henry Mo and Jerry Cai
Amherst Pierpont Securities, Stamford, CT
Stephen Stanley
Bank of America Merrill Lynch, New York, NY
Ethan Harris
Barclays, New York, NY
Michael Gapen
BMO Capital Markets Economics, Toronto, Canada
Douglas Porter
BNP Paribas North America, New York, NY
Bricklin Dwyer
Chase Wealth Management, New York, NY
Anthony Chan
Chmura Economics & Analytics, Richmond, VA
Christine Chmura and Xiaobing Shuai
Comerica, Dallas, TX
Robert A. Dye
Cycledata Corp., San Diego, CA
Robert S. Powers
Daiwa Capital Markets America, New York, NY
Michael Moran
DePrince & Associates, Murfreesburo, TN
Albert E. DePrince Jr.
Grant Thornton, Chicago, IL
Diane Swonk
Economist Intelligence Unit, New York, NY
Leo Abruzzese and Jan Friederich
Fannie Mae, Washington, DC
Douglas Duncan
Georgia State University, Atlanta, GA
Rajeev Dhawan
GLC Financial Economics, Providence, RI
Gary L. Ciminero
Goldman, Sachs & Co., New York, NY
Jan Hatzius
High Frequency Economics, Valhalla NY
James O'Sullivan
IHSMarkit
Nariman Behravesh, London, England
J.P. Morgan Chase, New York, NY
Bruce Kasman
Loomis, Sayles & Company, L.P., Boston, MA
Brian Horrigan
MacroFin Analytics, Wayne, NJ
Parul Jain
Moody's Analytics, West Chester, PA
Mark M. Zandi
Moody's Capital Markets Group, New York, NY
John Lonski
MUFG Union Bank, New York, NY
Christopher S. Rupkey
Naroff Economic Advisors, Philadelphia, PA
Joel L. Naroff
NatWest Markets, Greenwich, CT
Michelle Girard and Kevin Cummins
Nomura Securities International, Inc., New York, NY
Lewis Alexander
Oxford Economics, New York, NY
Gregory Daco
PNC Financial Services Group, Pittsburgh, PA
Gus Faucher
RDQ Economics, New York, NY
John Ryding and Conrad DeQuadros
Regions Financial Corporation, Birmingham, AL
Richard F. Moody
Via Nova Investment Management, Fredericksburg, VA
Alan Gayle
Scotiabank Group, Toronto, Canada
Jean-Francois Perrault and Brett House
Societe Generale, NY, New York
Stephen W. Gallagher
S&P Global, New York, NY
Beth Ann Bovino
Stone Harbor Investment Partners, LP, New York, NY
Brian Keyser
Swiss Re, New York, NY
Kurt Karl
The Northern Trust Company, Chicago, IL
Carl Tannenbaum
TS Lombard, London, UK
Steven Blitz
UBS AG, New York, NY
Samuel Coffin
Wells Capital Management, San Francisco, CA
Gary Schlossberg
Wells Fargo, Charlotte, NC
Jay Bryson and Mark Vitner

CONTRIBUTORS TO INTERNATIONAL SURVEY

AIG, New York, NY
Barclays Capital, New York, NY
BNP Paribas Americas, New York, NY
ING Financial Markets, London, England
Mizuho Research Institute, Tokyo, Japan
Moody's Analytics, West Chester, PA
Moody's Capital Markets Group, New York, NY
Nomura Securities International, New York, NY
Oxford Economics, Wayne, PA
Scotiabank Group, Toronto, Canada
TS Lombard, London, UK
UBS, New York, NY
Wells Fargo, Charlotte, NC

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

Vol. 37, No. 9, September 1, 2018

Wolters Kluwer

BLUE CHIP FINANCIAL FORECASTS®

Executive Editor:
Joseph Aguinaldo
Director of Data Research & Documentation
Haver Analytics
60 East 42nd Street
New York, NY 10165
Phone (212) 986-9300
E-mail: *bluechip@haver.com*

Founder: Robert J. Eggert
Randell E. Moore, Editor Emeritus
Dom Cervi, Publisher

Blue Chip Financial Forecasts® (ISSN: 0741-8345) is published monthly by CCH Incorporated, 76 Ninth Avenue, New York, NY 10011. Printed in the U.S.A.

Subscriptions: $1,595 per year for print delivery of 12 monthly issues. For alternate formats (PDF, Excel, online), multiple-copy rates and site-license agreements call Nelson Pereira in the U.S. at 212-771-0701. You may also contact him at: nelson.pereira@wolterskluwer.com

Permission requests: For information on how to obtain permission to reproduce content, please visit the Wolters Kluwer website at: http://www.wklawbusiness.com/footer-pages/permissions

Purchasing reprints: For customized article reprints, please contact *Wright's Media* at 1-877-652-5295 or go to the *Wright's Media* website at *www.wrightsmedia.com.*

Customer Service: 1-800-234-1660
To Order: 1-800-638-8437
Customer Service Fax: 1-800-901-9075
Email: customer.service@wolterskluwer.com
Web Site:
https://lrus.wolterskluwer.com/corporate/blue-chip/

TABLE OF CONTENTS

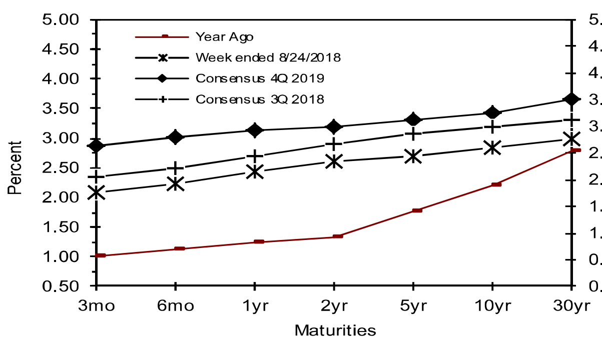
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Qtr	3Q	4Q	1Q	2Q	3Q	4Q
Interest Rates	Aug 24	Aug 17	Aug 10	Aug 3	July	June	May	Q2 2018	2018	2018	2019	2019	2019	2019
Federal Funds Rate	1.92	1.91	1.91	1.91	1.91	1.81	1.70	1.73	**2.0**	**2.2**	**2.4**	**2.6**	**2.8**	**2.9**
Prime Rate	5.00	5.00	5.00	5.00	5.00	4.88	4.75	4.79	**5.0**	**5.3**	**5.5**	**5.7**	**5.9**	**6.0**
LIBOR, 3-mo.	2.31	2.32	2.34	2.34	2.34	2.33	2.34	2.34	**2.4**	**2.6**	**2.8**	**3.0**	**3.1**	**3.2**
Commercial Paper, 1-mo.	1.95	1.95	1.95	1.96	1.96	1.92	1.82	1.86	**2.0**	**2.3**	**2.5**	**2.7**	**2.8**	**2.9**
Treasury bill, 3-mo.	2.08	2.07	2.06	2.03	1.99	1.94	1.90	1.88	**2.1**	**2.3**	**2.5**	**2.6**	**2.8**	**2.9**
Treasury bill, 6-mo.	2.24	2.24	2.24	2.22	2.16	2.11	2.07	2.06	**2.2**	**2.4**	**2.6**	**2.8**	**2.9**	**3.0**
Treasury bill, 1 yr.	2.44	2.44	2.44	2.44	2.38	2.31	2.28	2.25	**2.4**	**2.6**	**2.8**	**2.9**	**3.0**	**3.1**
Treasury note, 2 yr.	2.61	2.62	2.65	2.66	2.60	2.51	2.53	2.48	**2.7**	**2.8**	**2.9**	**3.1**	**3.1**	**3.2**
Treasury note, 5 yr.	2.71	2.75	2.80	2.85	2.77	2.76	2.84	2.76	**2.9**	**3.0**	**3.1**	**3.2**	**3.3**	**3.3**
Treasury note, 10 yr.	2.83	2.87	2.94	2.97	2.88	2.90	3.00	2.92	**3.0**	**3.1**	**3.2**	**3.3**	**3.4**	**3.4**
Treasury note, 30 yr.	2.98	3.04	3.09	3.11	3.00	3.04	3.15	3.08	**3.1**	**3.3**	**3.4**	**3.5**	**3.6**	**3.7**
Corporate Aaa bond	3.99	4.04	4.06	4.10	4.06	4.09	4.12	4.07	**4.1**	**4.3**	**4.5**	**4.6**	**4.7**	**4.8**
Corporate Baa bond	4.71	4.76	4.77	4.79	4.79	4.81	4.79	4.74	**4.9**	**5.1**	**5.3**	**5.4**	**5.5**	**5.6**
State & Local bonds	3.62	3.63	3.65	3.63	3.60	3.62	3.65	3.63	**3.8**	**4.0**	**4.1**	**4.2**	**4.3**	**4.4**
Home mortgage rate	4.51	4.53	4.59	4.60	4.53	4.57	4.59	4.54	**4.6**	**4.7**	**4.9**	**5.0**	**5.1**	**5.1**

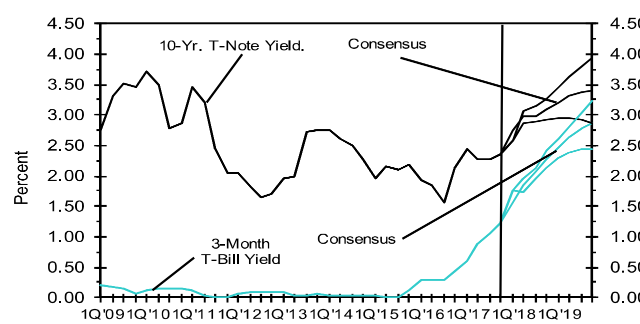
	History								Consensus Forecasts-Quarterly					
	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q
Key Assumptions	2016	2016	2017	2017	2017	2017	2018	2018	2018	2018	2019	2019	2019	2019
Major Currency Index	90.2	93.6	94.3	92.9	88.3	88.9	86.1	88.3	**89.8**	**89.9**	**89.8**	**89.6**	**89.2**	**88.9**
Real GDP	1.9	1.8	1.8	3.0	2.8	2.3	2.2	4.2	**3.1**	**2.8**	**2.4**	**2.4**	**2.1**	**1.9**
GDP Price Index	1.4	2.3	2.0	1.2	2.2	2.5	2.0	3.0	**2.2**	**2.3**	**2.3**	**2.3**	**2.2**	**2.2**
Consumer Price Index	1.8	2.7	3.0	0.1	2.1	3.3	3.5	1.7	**2.3**	**2.3**	**2.4**	**2.2**	**2.3**	**2.3**

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; LIBOR quotes from Intercontinental Exchange. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).

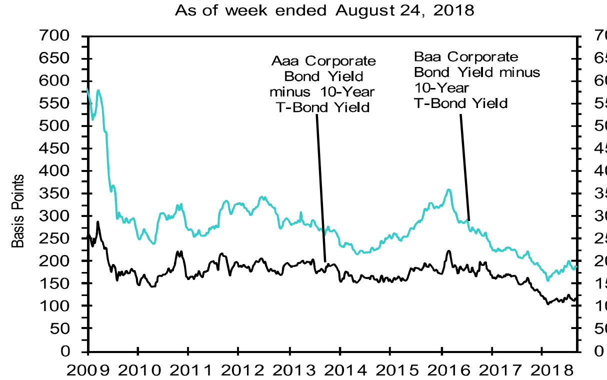
U.S. Treasury Yield Curve
Week ended August 24, 2018 and Year Ago vs.
3Q 2018 and 4Q 2019 Consensus Forecasts



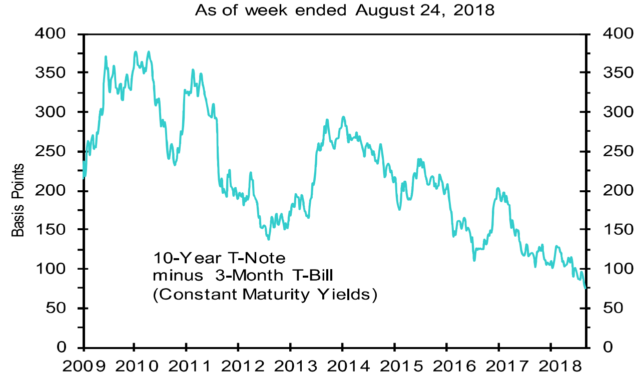
U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield
(Quarterly Average)
Forecast



Corporate Bond Spreads
As of week ended August 24, 2018



U.S. Treasury Yield Curve
As of week ended August 24, 2018



Tax Reform Impact on the U.S. Utilities, Power & Gas Sector

Tax Reform Creates Near-Term Credit Pressure for Regulated Utilities and Holding Companies

Regulatory Support Key to Mitigating Downward Migration in Ratings

Near-Term Pressure on Credit Metrics: The Tax Cuts and Jobs Act signed into law on Dec. 22, 2017 has negative credit implications for regulated utilities and utility holding companies over the short to medium term. A reduction in customer bills to reflect lower federal income taxes and return of excess accumulated deferred income taxes (ADIT) is expected to lower revenues and FFO across the sector. Absent mitigating strategies on the regulatory front, this is expected to lead to weaker credit metrics and negative rating actions for issuers with limited headroom to absorb the leverage creep.

Significant Hit to FFO: To analyse the impact of the tax reform bill across our utility coverage, Fitch Ratings studied a sample of 140 regulated operating subsidiaries and utility holding companies. We estimate that regulated utility subsidiaries will, on average, see an approximately 6% reduction in net revenues if tax changes are reflected in customer bills right away. Fitch has assumed that a substantial portion of the excess ADIT will be returned to customers over the life of the utility property. The lower revenue translates to an approximately 15% reduction in FFO that drives an approximately 45 basis point increase in FFO-adjusted leverage across our sample.

Regulatory Response and Financial Policy Key: State regulators have begun to examine the impact of tax reform on regulated utilities in their states. While most state regulators will seek to provide some sort of rate relief to customers, they may be open to a negotiated outcome that also preserves the creditworthiness of the utilities. Management actions to defend their credit profiles are also important in assessing the future rating trajectory of an issuer. Overall, Fitch expects rating actions to be limited and on a case-by-case basis. Holding companies are more vulnerable given the elevated leverage profile for many, driven by past debt-funded acquisitions.

Longer-Term Positive: Over a longer-term perspective, Fitch views tax reform as modestly positive for utilities. The sector retained the deductibility of interest expense, which would have otherwise significantly impacted cost of capital for this capital-intensive sector. The exemption from 100% capex expensing is also welcome news for the sector, which has seen years of bonus depreciation inflate ADIT, which is netted from the rate base in most state regulatory jurisdictions. The excess ADIT will be recorded as a regulatory liability, which will amortize over time, leading to rate base and earnings growth. Finally, the reduction in federal income taxes lowers cost of service to customers, providing utilities headroom to increase rates for capital investments.

In this report, Fitch Ratings addresses the following frequently asked questions from investors:

- How does tax reform affect regulated utilities?
- What is the impact of tax reform on utility holding companies and nonregulated businesses?
- What is the magnitude of FFO reduction and leverage increase for the sector?
- Does Fitch expect to take widespread rating actions driven by tax law changes?
- Which issuers does Fitch consider most at risk for negative rating actions?

How Does Tax Reform Affect Regulated Utilities?

The Tax Cuts and Jobs Act has negative credit implications for the regulated utilities and several utility holding companies over the short to medium term. A reduction in customer bills to reflect lower federal income taxes and return of excess ADIT to customers is expected to lower revenues and FFO across the sector. Absent mitigating strategies on the regulatory front, this is expected to lead to weaker credit metrics and negative rating actions for those issuers that have limited headroom to absorb the leverage creep. The end of bonus depreciation or the "interest-free loan" from the federal government and reduced FFO at a time when capex budgets are elevated will necessitate greater reliance on equity and debt funding for the utility subsidiaries. This could lead to higher costs of capital for the sector, especially if regulators require an immediate reduction in customer bills to reflect the tax law changes.

It is important to note that the negative impact on cash flows and leverage metrics is primarily being driven by timing-related differences. Due to availability of 100% and 50% bonus depreciation on qualified property in recent years, most utilities have not been paying cash taxes and have seen a sharp buildup in ADIT. This situation would have reversed over time, and our financial forecasts did reflect a hit to FFO for most utilities as they returned to full cash taxpaying status by 2020–2021. With tax reform, utilities cannot claim bonus depreciation anymore, the ADIT has to be recalculated at the new 21% rate, the future ADIT also builds at the 21% rate, and the excess ADIT has to be refunded to customers, leading to lower FFO expectation compared to prior Fitch estimates. Since federal income taxes are included in a utility's cost of service, this is typically a straight pass-through cost. With most utilities not paying cash taxes, the reduction in revenue requirement due to lower federal taxes does not have an equivalent offset. Hence, past bonus depreciation benefits have exacerbated the situation for utilities, leading to unanticipated near-term pressure on FFO.

Over a longer-term perspective, Fitch views tax reform as modestly positive for utilities. The sector retained the deductibility of interest expense, which would have otherwise significantly impacted cost of capital for this capital-intensive sector. The exemption from 100% capex expensing is also welcome news for the sector, which has seen years of bonus depreciation benefits supress rate base (for most states, ADIT reduces the rate base on which a utility earns a return). Finally, the reduction in federal income taxes lowers cost of service to customers, providing utilities headroom to increase rates for capital investments. Fitch estimates that electric utility customers could, on average, see approximately 3%–5% reduction in their bills due to tax law changes.

What Is the Impact of Tax Reform on Utility Holding Companies and Nonregulated Businesses?

At the holding company level, the reduction in utility subsidiaries' cash flows will weaken the consolidated cash flow profile, leading to higher leverage unless mitigated by holdco debt reduction. In addition, there continues to be limited clarity surrounding the deductibility of holding company interest, in particular the methodology to allocate consolidated interest expense between regulated and nonregulated businesses. Until resolved, these issues will continue to weigh on the financial policies of holding companies.

There is no ambiguity in how interest expense will be treated for regulated and nonregulated entities. Regulated subsidiaries will be able to fully deduct interest expense for tax purposes, and nonregulated businesses, similar to other corporations, will be subject to the 30% of EBITDA limitation (which changes to 30% of EBIT in 2022). Calculating interest deductibility for holding companies gets complicated. For holdcos such as NextEra Energy, Inc., which has distinct regulated and nonregulated debt issuing entities, the analysis is straightforward. However, for other holdcos such as Dominion Energy, Inc., which issues debt for nonregulated businesses at the holdco level, or even for holdcos such as Exelon Corporation and FirstEnergy Corporation, which issue debt at their nonregulated entities, it is not clear how the consolidated interest expense will be allocated between regulated and nonregulated businesses. Several managements we spoke to seem to believe that asset-based allocation, such as that used for allocation of interest for foreign corporations, will be applicable. As a broader issue, we are most concerned with allocation of holdco interest expense to regulated businesses to claim full deductibility of interest expense, since regulated subsidiaries already meet their prescribed capital structure. We expect uncertainty to prevail until the U.S. Treasury department issues guidance in this regard.

For nonregulated businesses, the reduction in federal income taxes is positive because the benefit accrues straight to the bottom line. Fitch expects renewable business to be negatively impacted since the federal renewable tax credits are less valuable at the lower tax rate, thus making renewable economics less favorable. Fitch also expects less tax equity to be available as a source of financing, which is likely to hit the small renewable developers disproportionately. In this regard, solar developers may be more significantly impacted than wind developers due to the large upfront solar investment tax credit (ITC) that needs to be absorbed versus a 10-year life of wind production tax credits (PTCs). A lower tax rate also lowers the net present value of accumulated renewable tax credits and accumulated net operating losses by extending the time period over which these will be used.

What Is the Magnitude of FFO Reduction and Leverage Increase for the Sector?

We have analyzed the cash flow impact for the sector while admitting that tax and accounting nuances overlaid by the complexity of regulatory accounting makes the exercise challenging. After analyzing a sample of 140 regulated operating subsidiaries and utility holding companies, we estimate that regulated utility subsidiaries will, on average, see an approximately 6% reduction in net revenues if the tax reform changes are reflected in rates right away. This reduction in revenues translates to an approximately 15% reduction in FFO and an approximately 45 basis point increase in FFO-adjusted leverage across our sample.

Key inputs and assumptions incorporated in our analysis include:

- **Immediate reduction in customer bills to reflect the cut in federal tax rate to 21% from 35%:** Under cost-of-service regulation, federal and state income taxes are treated as an expense that is recoverable in regulatory tariffs. The reduction in federal income tax rate will lower the income tax expense, thus leading to lower revenue requirement for a regulated utility. As highlighted above, due to prior bonus depreciation benefits, most utilities are not paying cash taxes. As a result, immediate reduction in customer bills to reflect the lower revenue requirement will lead to lower FFO.
- **95% of ADIT, as reported on LTM basis, was assumed to be protected:** Based on our survey of regulated utilities, it appears a vast majority of the ADIT reported on the balance sheet pertain to public utility property and arise from accelerated federal tax depreciation and investment tax credits on that property, and, therefore, are protected by IRS normalization requirements. As a rough rule of thumb for our sample, we assumed that 95% of ADIT is protected and 5% unprotected, while recognizing that actual amounts may vary by utility.
- **Return of the excess protected ADIT over 30 years and excess unprotected ADIT over five years:** Section 203(e) of the Tax Reform Act of 1986, also known as the Average Rate Assumption Method (ARAM), provided for the reduction in protected ADIT due to the reduction in the tax rate to be spread over the life of the related property. Fitch has assumed that similar ARAM will be applicable for the Tax Cuts and Jobs Act, which seems consistent with the approach that most utilities are taking. The average life of utility property varies by utility, but 30 years serves as a good approximation. The return of unprotected ADIT is not subject to IRS normalization rules and, hence, will be subject to discretion of the regulators. While the regulatory approach with respect to unprotected ADIT varied across states in 1986, for the purpose of our exercise, we have assumed that regulators will require excess unprotected ADIT to be returned to customers over a five-year period.
- **Net PPE-based allocation methodology for holding company interest:** For the purpose of our exercise, we have allocated the consolidated interest expense between regulated and nonregulated businesses using net PPE as a proxy.
- **No adjustments made for bonus depreciation:** We have not made adjustments for the loss in bonus depreciation for years 2018 and 2019 (versus prior benefits at 40% and 30% for property placed in service in 2018 and 2019, respectively). The negative impact will be partially offset by bonus depreciation on capex incurred until Sept. 29, 2017 for property placed in service in 2018.

Does Fitch Expect to Take Widespread Rating Actions Driven by Tax Law Changes?

Fitch's rating actions will be guided by both the regulatory and management responses. A majority of states have opened dockets or requested all utilities in the state to submit an analysis on the implications of the tax reform. While regulators will be keen to provide some sort of rate relief for customers, such actions could take many forms and vary in time frame. Some jurisdictions may be open to a negotiated outcome that focuses more on benefits of rate stability and creditworthy utilities rather than immediate rate reductions. In the former, many tools could be employed, including the following:

- Deferral of lower tax expense to use as an offset to expected future rate increases either from the recovery of regulatory deferrals or rate base growth
- Return of excess unprotected ADIT over a longer-term horizon
- Increase in authorized equity ratio and/or return on equity
- Accelerated depreciation on some assets
- Lower capex

The time frame for regulatory action is an important consideration and will be varied. Some jurisdictions have asked for tax savings to be returned to customers immediately, thereby creating a decline in cash flow on day one. Some jurisdictions have directed utilities to segregate the effect of lower taxes to consider in future ratemaking procedures, and therefore result in no near-term change to cash flow. Some companies are in the middle of multiyear rate plans or rate settlements that do not provide for changes in tax rate, while other rate arrangements have incorporated mechanisms for lower taxes. Lastly, managements' responses to defend their credit profiles in the face of prospective lower cash flow will be key. If Fitch sees a credible path for credit metrics to be restored commensurate with the existing rating level, no rating actions may be warranted.

Holding companies are more vulnerable to negative rating actions given the elevated leverage profile for many, driven by past debt-funded acquisitions. The cash flow profile of holdcos will be weaker than prior expectations due to regulated utility subsidiaries bearing the brunt of tax law changes, leading to lower cash tax and possibly lower dividend distributions to parent holding companies. Moreover, funding needs at regulated subsidiaries will increase with the elimination of bonus depreciation. Conversely, the nonregulated subsidiaries will benefit from tax reform, which will be positive for parent holding companies.

Which Issuers Does Fitch Consider Most at Risk for Negative Rating Actions?

Issuers with limited headroom at the current rating level that are close to their negative rating triggers as established by Fitch are more vulnerable to negative rating actions. The most susceptible issuers are those that already have a Negative Outlook or are on Negative Rating Watch.

Key Rating Triggers for Select Issuers on Negative Outlook or Rating Watch

Issuer	IDR	Outlook/ Watch	Pre-Tax Reform FFO-Adjusted Leverage 2018F (x)	Key Downgrade Trigger	Key Upgrade Trigger
DTE Energy Co.	BBB+	Negative Outlook	4.6	Material delays associated with permitting and constructing the NEXUS pipeline, along with FFO-adjusted leverage sustaining > 4.5x.	Sustained FFO-adjusted leverage to 4.0x or better.
Duke Energy Corp.	BBB+	Negative Outlook	5.4	Inability to recover coal ash costs and sustained FFO-adjusted leverage > 5.1x by 2019.	Unlikely in medium term.
Georgia Power Co.	A	Negative Rating Watch	4.4	Proceeding with construction of new nuclear units while retaining material exposure to further costs and schedule overruns, and FFO-adjusted leverage > 4.3x on a sustained basis.	Unlikely in medium term.
SCANA Corp.	BB+	Negative Rating Watch	8.1	Material unrecoverable costs for the abandoned new nuclear project, constrained liquidity and adjusted debt/EBITDAR > 5.5x.	Constructive resolution of the stranded new nuclear project and adjusted debt/EBITDAR < 4.5x.
Southern Company	A–	Negative Rating Watch	5.2	Downgrade of Georgia Power Co. and FFO-adjusted leverage sustaining > 4.7x by 2019.	Unlikely in medium term.
WGL Holdings, Inc.	A–	Negative Rating Watch	4.2	Ownership by a weaker parent after acquisition is completed, and FFO-adjusted leverage > 4.0x.	Unlikely in medium term.

Source: Fitch.

Related Research

Fitch 2018 Outlook: U.S. Utilities, Power & Gas (Supportive Regulation and Low Commodity Costs Support Stable Outlook) (November 2017)
U.S. Utility Parent Companies Handbook (A Detailed Review of Utility Parent Companies — Third Edition) (November 2017)
U.S. Competitive Generators Handbook (A Detailed Review of Competitive Generation Companies) (October 2017)
U.S. Regulated Utility Parent Holding Companies Peer Comparison (October 2017)
U.S. Integrated Electric Utilities Handbook (A Detailed Review of Integrated Electric Utilities) (August 2017)
U.S. Transmission and Distribution Utilities Handbook (Detailed Review of Electric and Gas T&D Utilities — Third Edition) (May 2017)

Analysts

Shalini Mahajan
+1 212 908-0351
shalini.mahajan@fitchratings.com

Barbara Chapman
+1 646 582-4886
barbara.chapman@fitchratings.com

Michael Giannone
+1 646 582-4990
michael.giannone@fitchratings.com

Benjamin Saliterman
+1 212 908-9108
benjamin.saliterman@fitchratings.com

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform

Global Credit Research - 19 Jan 2018

New York, January 19, 2018 -- Moody's Investors Service, ("Moody's") has changed the rating outlooks to negative from stable for 24 regulated utilities and utility holding companies; and to stable from positive for one utility holding company in the United States. The short-term and long-term ratings for all 25 companies were affirmed.

RATINGS RATIONALE

"Today's action primarily applies to companies that already had limited cushion in their rating for deterioration in financial performance, will be incrementally impacted by changes in the tax law and where we now expect key credit metrics to be lower for longer," said Jim Hempstead, a Managing Director at Moody's. "Utilities will work closely with state regulators to try to mitigate the negative impact of tax reform and in some cases they may seek to refine their corporate financial policies. Where successful, their rating outlooks could revert to stable."

Tax reform is credit negative for US regulated utilities because the lower 21% statutory tax rate reduces cash collected from customers, while the loss of bonus depreciation reduces tax deferrals, all else being equal. Moody's calculates that the recent changes in tax laws will dilute a utility's ratio of cash flow before changes in working capital to debt by approximately 150 - 250 basis points on average, depending to some degree on the size of the company's capital expenditure programs. From a leverage perspective, Moody's estimates that debt to total capitalization ratios will increase, based on the lower value of deferred tax liabilities.

The change in outlook to negative from stable for the 24 companies affected in this rating action primarily reflects the incremental cash flow shortfall caused by tax reform on projected financial metrics that were already weak, or were expected to become weak, given the existing rating for those companies. The negative outlook also considers the uncertainty over the timing of any regulatory actions or other changes to corporate finance polices made to offset the financial impact.

The change in outlook to stable from positive for American Electric Power Company, Inc. (AEP, Baa1 stable) reflects Moody's calculations that the projected ratio of cash flow before changes in working capital to debt, incorporating the effects of tax reform, will remain in the mid-teens range. At this level, Moody's believes AEP's Baa1 rating is appropriate.

The vast majority of US regulated utilities, however, continue to maintain stable rating outlooks. We do not expect the cash flow reduction associated with tax reform to materially impact their credit profiles because sufficient cushion exists within projected financial metrics for their current ratings. Nonetheless, further actions could occur on a company specific basis.

Over the next 12 to 18 months, Moody's will continue to monitor the financial impact of tax reform on each company, including its regulatory approach to rate treatment and any changes to corporate finance strategies. This will include balance sheet changes due to the reclassification of excess deferred tax liabilities as a regulatory liability and the magnitude of any amounts to be refunded to customers. If the financial impact of tax reform is more severe than Moody's initial estimates or the companies fail to materially mitigate any weaknesses in their financial profiles, the ratings could be downgraded.

That said, Moody's expects that most utilities will attempt to manage any negative financial implications of tax reform through regulatory channels. Corporate financial policies could also change. The actions taken by utilities will be incorporated into the credit analysis on a prospective basis. As a result, it is conceivable that some companies will sufficiently defend their credit profiles. For these companies, it is possible for the outlook to return to stable.

Potential regulatory offsets to tax-related cash leakage could include: accelerated cost recovery of certain regulatory assets or future investment; changes to the equity layer or allowed ROEs in rates, and other actions. Changes to corporate financial policies could include changes to capitalization, the financing of future investments, dividend growth, or others. Some of these corporate measures could have a more immediate boost to projected metrics than certain regulatory provisions, which may take time to approve and implement.

Outlook Actions:

..Issuer: American Electric Power Company, Inc.

....Outlook, Changed To Stable From Positive

..Issuer: Avista Corp.

....Outlook, Changed To Negative From Stable

..Issuer: Avista Corp. Capital II

....Outlook, Changed To Negative From Stable

..Issuer: Duke Energy Corporation

....Outlook, Changed To Negative From Stable

..Issuer: Entergy Corporation

....Outlook, Changed To Negative From Stable

..Issuer: New Jersey Natural Gas Company

....Outlook, Changed To Negative From Stable

..Issuer: Northwest Natural Gas Company

....Outlook, Changed To Negative From Stable

..Issuer: ONE Gas, Inc

....Outlook, Changed To Negative From Stable

..Issuer: Piedmont Natural Gas Company, Inc.

....Outlook, Changed To Negative From Stable

..Issuer: Public Service Company of Oklahoma

....Outlook, Changed To Negative From Stable

..Issuer: Questar Gas Company

....Outlook, Changed To Negative From Stable

..Issuer: South Jersey Gas Company

....Outlook, Changed To Negative From Stable

..Issuer: Alabama Power Capital Trust V

....Outlook, Changed To Negative From Stable

..Issuer: Alabama Power Company

....Outlook, Changed To Negative From Stable

..Issuer: Southern Company (The)

....Outlook, Changed To Negative From Stable

..Issuer: Southern Elect Generating Co

....Outlook, Changed To Negative From Stable

..Issuer: Southwestern Public Service Company

....Outlook, Changed To Negative From Stable

..Issuer: Wisconsin Gas LLC

....Outlook, Changed To Negative From Stable

..Issuer: American Water Capital Corp.

....Outlook, Changed To Negative From Stable

Issuer: American Water Works Company, Inc.

....Outlook, Changed To Negative From Stable

Outlook Actions:

..Issuer: Consolidated Edison Company of New York, Inc.

....Outlook, Changed To Negative From Stable

..Issuer: Consolidated Edison, Inc.

....Outlook, Changed To Negative From Stable

..Issuer: Orange and Rockland Utilities, Inc.

....Outlook, Changed To Negative From Stable

..Issuer: Brooklyn Union Gas Company, The

....Outlook, Changed To Negative From Stable

..Issuer: KeySpan Gas East Corporation

....Outlook, Changed To Negative From Stable

Affirmations:

..Issuer: American Electric Power Company, Inc.

.... Commercial Paper, Affirmed P-2

....Senior Unsecured Shelf, Affirmed (P)Baa1

....Junior Subordinated Shelf, Affirmed (P)Baa2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

..Issuer: Avista Corp.

.... Issuer Rating, Affirmed Baa1

....Senior Secured First Mortgage Bonds, Affirmed A2

....Underlying Senior Secured First Mortgage Bonds, Affirmed A2

....Senior Secured Medium-Term Note Program, Affirmed (P)A2

....Senior Secured Regular Bond/Debenture, Affirmed A2

....Senior Unsecured Medium-Term Note Program, Affirmed (P)Baa1

..Issuer: Avista Corp. Capital II

....Pref. Stock Preferred Stock, Affirmed Baa2

..Issuer: Duke Energy Corporation

.... Issuer Rating, Affirmed Baa1

....Junior Subordinated Regular Bond/Debenture, Affirmed Baa2

....Senior Unsecured Shelf, Affirmed (P)Baa1

....Senior Unsecured Bank Credit Facility, Affirmed Baa1

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

..Issuer: Entergy Corporation

.... Issuer Rating, Affirmed Baa2

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa2

....Senior Unsecured Shelf, Affirmed (P)Baa2

..Issuer: New Jersey Natural Gas Company

.... Commercial Paper, Affirmed P-1

..Issuer: Northwest Natural Gas Company

.... Commercial Paper, Affirmed P-2

....Senior Secured Medium-Term Note Program, Affirmed (P)A1

....Senior Unsecured Medium-Term Note Program, Affirmed (P)A3

....Senior Secured Shelf, Affirmed (P)A1

....Senior Unsecured Shelf, Affirmed (P)A3

....Preferred Shelf, Affirmed (P)Baa2

....Senior Secured First Mortgage Bonds, Affirmed A1

....Senior Secured Regular Bond/Debenture, Affirmed A1

..Issuer: ONE Gas, Inc

....Senior Unsecured Commercial Paper, Affirmed P-1

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

..Issuer: Piedmont Natural Gas Company, Inc.

....Senior Unsecured Commercial Paper, Affirmed P-1

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

..Issuer: Public Service Company of Oklahoma

.... Issuer Rating, Affirmed A3

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

..Issuer: Questar Gas Company

....Senior Unsecured Commercial Paper, Affirmed P-1

....Senior Unsecured Medium-Term Note Program, Affirmed (P)A2

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

..Issuer: Alabama Power Capital Trust V

....Pref. Stock Preferred Stock, Affirmed A2

..Issuer: Alabama Power Company

.... Commercial Paper, Affirmed P-1

.... Issuer Rating, Affirmed A1

....Senior Unsecured Shelf, Affirmed (P)A1

....Preferred Shelf, Affirmed (P)A3

....Preference Shelf, Affirmed (P)A3

....Pref. Stock Preferred Stock, Affirmed A3

....Senior Unsecured Bank Credit Facility, Affirmed A1

....Senior Unsecured Commercial Paper, Affirmed P-1

....Senior Unsecured Regular Bond/Debenture, Affirmed A1

..Issuer: Columbia (Town of) AL, Industrial Dev. Board

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Eutaw (City of) AL, Industrial Dev. Board

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Mobile (City of) AL, I.D.B.

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Walker County Econ & Ind Dev Authority

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: West Jefferson (Town of) AL, Ind. Devel. Bd.

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Wilsonville (Town of) AL, I.D.B.

....Senior Unsecured Revenue Bonds, Affirmed A1

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

....Underlying Senior Unsecured Revenue Bonds, Affirmed A1

..Issuer: South Jersey Gas Company

.... Issuer Rating, Affirmed A2

....Senior Secured First Mortgage Bonds, Affirmed Aa3

....Senior Secured Medium-Term Note Program, Affirmed (P)Aa3

....Senior Secured Regular Bond/Debenture, Affirmed Aa3

....Senior Unsecured Commercial Paper, Affirmed P-1

..Issuer: New Jersey Economic Development Authority

....Senior Secured Revenue Bonds, Affirmed Aa3

....Underlying Senior Secured Revenue Bonds, Affirmed Aa3

....Senior Secured Revenue Bonds, Affirmed Aa2

....Underlying Senior Secured Revenue Bonds, Affirmed Aa2

..Issuer: Southern Company (The)

.... Commercial Paper, Affirmed P-2

....Junior Subordinated Regular Bond/Debenture, Affirmed Baa3

....Senior Unsecured Shelf, Affirmed (P)Baa2

....Junior Subordinated Shelf, Affirmed (P)Baa3

....Senior Unsecured Bank Credit Facility, Affirmed Baa2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa2

..Issuer: Southern Elect Generating Co

.... Issuer Rating, Affirmed A2

....Senior Unsecured Regular Bond/Debenture, Affirmed A1

..Issuer: Southwestern Public Service Company

.... Issuer Rating, Affirmed Baa1

....Senior Secured Shelf, Affirmed (P)A2

....Senior Unsecured Shelf, Affirmed (P)Baa1

....Senior Secured First Mortgage Bonds, Affirmed A2

....Senior Unsecured Bank Credit Facility, Affirmed Baa1

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

..Issuer: Wisconsin Gas LLC

.... Commercial Paper, Affirmed P-1

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

..Issuer: American Water Capital Corp.

.... Issuer Rating, Affirmed A3

....Senior Unsecured Shelf, Affirmed (P)A3

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

..Issuer: American Water Works Company, Inc.

.... Issuer Rating, Affirmed A3

..Issuer: Berks County Industrial Development Auth., PA

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: California Pollution Control Financing Auth.

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: Illinois Development Finance Authority

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: Illinois Finance Authority

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: Indiana Finance Authority

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: MARICOPA COUNTY INDUSTRIAL DEVELOPMENT AUTHORITY,AZ

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: Northampton County I.D.A., PA

....Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: Owen (County of) KY

....Senior Unsecured Revenue Bonds, Affirmed A3

.Issuer: Consolidated Edison Company of New York, Inc.

.... Issuer Rating, Affirmed A2

....Senior Unsecured Shelf, Affirmed (P)A2

....Subordinate Shelf, Affirmed (P)A3

....Preferred Shelf, Affirmed (P)Baa1

....Senior Unsecured Commercial Paper, Affirmed P-1

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

....Underlying Senior Unsecured Regular Bond/Debenture, Affirmed A2

..Issuer: New York State Energy Research & Dev. Auth.

....Senior Unsecured Revenue Bonds, Affirmed A2

....Underlying Senior Unsecured Revenue Bonds, Affirmed A2

..Issuer: New York State Research & Development Auth.

....Senior Unsecured Revenue Bonds, Affirmed A2

....Underlying Senior Unsecured Revenue Bonds, Affirmed A2

..Issuer: Consolidated Edison, Inc.

.... Issuer Rating, Affirmed A3

....Senior Unsecured Shelf, Affirmed (P)A3

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

..Issuer: Orange and Rockland Utilities, Inc.

.... Issuer Rating, Affirmed A3

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

..Issuer: Brooklyn Union Gas Company, The

....LT Issuer Rating, Affirmed A2

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

..Issuer: New York State Energy Research & Dev. Auth.

....Backed LT IRB/PC Insured, Affirmed A2

...Underlying LT IRB/PC, Affirmed A2

Issuer: KeySpan Gas East Corporation

....LT Issuer Rating, Affirmed A2

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

The principal methodology used in rating Public Service Company of Oklahoma, Southwestern Public Service Company, Southern Company (The), Alabama Power Company, Alabama Power Capital Trust V, Southern Elect Generating Co, South Jersey Gas Company, Wisconsin Gas LLC, American Electric Power Company, Inc., Duke Energy Corporation, Piedmont Natural Gas Company, Inc., Avista Corp., Avista Corp. Capital II, ONE Gas, Inc, New Jersey Natural Gas Company, Northwest Natural Gas Company, Questar Gas Company, Entergy Corporation, Consolidated Edison, Inc., Consolidated Edison Company of New York, Inc., Brooklyn Union Gas Company, The, KeySpan Gas East Corporation, and Orange and Rockland Utilities, Inc. was Regulated Electric and Gas Utilities published in June 2017. The principal methodology used in rating American Water Works Company, Inc. and American Water Capital Corp. was Regulated Water Utilities published in December 2015. Please see the Rating Methodologies page on www.moodys.com for a copy of these methodologies.

REGULATORY DISCLOSURES

For ratings issued on a program, series or category/class of debt, this announcement provides certain regulatory disclosures in relation to each rating of a subsequently issued bond or note of the same series or category/class of debt or pursuant to a program for which the ratings are derived exclusively from existing ratings in accordance with Moody's rating practices. For ratings issued on a support provider, this announcement provides certain regulatory disclosures in relation to the credit rating action on the support provider and in relation to each particular credit rating action for securities that derive their credit ratings from the support provider's credit rating. For provisional ratings, this announcement provides certain regulatory disclosures in relation to the provisional rating assigned, and in relation to a definitive rating that may be assigned subsequent to the final issuance of the debt, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive rating in a manner that would have affected the rating. For further information please see the ratings tab on the issuer/entity page for the respective issuer on www.moodys.com.

For any affected securities or rated entities receiving direct credit support from the primary entity(ies) of this credit rating action, and whose ratings may change as a result of this credit rating action, the associated regulatory disclosures will be those of the guarantor entity. Exceptions to this approach exist for the following disclosures, if applicable to jurisdiction: Ancillary Services, Disclosure to rated entity, Disclosure from rated entity.

Regulatory disclosures contained in this press release apply to the credit rating and, if applicable, the related rating outlook or rating review.

The relevant office for each credit rating is identified in "Debt/deal box" on the Ratings tab in the Debt/Deal List section of each issuer/entity page of the website.

Please see www.moodys.com for any updates on changes to the lead rating analyst and to the Moody's legal entity that has issued the rating.

Please see the ratings tab on the issuer/entity page on www.moodys.com for additional regulatory disclosures for each credit rating.

Ryan Wobbrock
Vice President - Senior Analyst
Infrastructure Finance Group
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

Jim Hempstead
MD - Utilities
Infrastructure Finance Group
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

Releasing Office:
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

MOODY'S
INVESTORS SERVICE

Moody's Investors Service, Inc., a wholly-owned credit rating agency subsidiary of Moody's Corporation ("MCO"), hereby discloses that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by Moody's Investors Service, Inc. have, prior to assignment of any rating, agreed to pay to Moody's Investors Service, Inc. for appraisal and rating services rendered by it fees ranging from $1,500 to approximately $2,500,000. MCO and MIS also maintain policies and procedures to address the independence of MIS's ratings and rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold ratings from MIS and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually at www.moodys.com under the heading "Investor Relations — Corporate Governance — Director and Shareholder Affiliation Policy."

Additional terms for Australia only: Any publication into Australia of this document is pursuant to the Australian Financial Services License of MOODY'S affiliate, Moody's Investors Service Pty Limited ABN 61 003 399 657AFSL 336969 and/or Moody's Analytics Australia Pty Ltd ABN 94 105 136 972 AFSL 383569 (as applicable). This document is intended to be provided only to "wholesale clients" within the meaning of section 761G of the Corporations Act 2001. By continuing to access this document from within Australia, you represent to MOODY'S that you are, or are accessing the document as a representative of, a "wholesale client" and that neither you nor the entity you represent will directly or indirectly disseminate this document or its contents to "retail clients" within the meaning of section 761G of the Corporations Act 2001. MOODY'S credit rating is an opinion as to the creditworthiness of a debt obligation of the issuer, not on the equity securities of the issuer or any form of security that is available to retail investors. It would be reckless and inappropriate for retail investors to use MOODY'S credit ratings or publications when making an investment decision. If in doubt you should contact your financial or other professional adviser.

Additional terms for Japan only: Moody's Japan K.K. ("MJKK") is a wholly-owned credit rating agency subsidiary of Moody's Group Japan G.K., which is wholly-owned by Moody's Overseas Holdings Inc., a wholly-owned subsidiary of MCO. Moody's SF Japan K.K. ("MSFJ") is a wholly-owned credit rating agency subsidiary of MJKK. MSFJ is not a Nationally Recognized Statistical Rating Organization ("NRSRO"). Therefore, credit ratings assigned by MSFJ are Non-NRSRO Credit Ratings. Non-NRSRO Credit Ratings are assigned by an entity that is not a NRSRO and, consequently, the rated obligation will not qualify for certain types of treatment under U.S. laws. MJKK and MSFJ are credit rating agencies registered with the Japan Financial Services Agency and their registration numbers are FSA Commissioner (Ratings) No. 2 and 3 respectively.

MJKK or MSFJ (as applicable) hereby disclose that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by MJKK or MSFJ (as applicable) have, prior to assignment of any rating, agreed to pay to MJKK or MSFJ (as applicable) for appraisal and rating services rendered by it fees ranging from JPY200,000 to approximately JPY350,000,000.

MJKK and MSFJ also maintain policies and procedures to address Japanese regulatory requirements.

MOODY'S
INVESTORS SERVICE

OUTLOOK
18 June 2018

Rate this Research

Contacts

Ryan Wobbrock +1.212.553.7104
VP-Senior Analyst
ryan.wobbrock@moodys.com

Poonam Thakur +1.212.553.4635
Associate Analyst
poonam.thakur@moodys.com

Yulia Rakityanskaya +1.416.214.3627
Associate Analyst
yulia.rakityanskaya@moodys.com

Robert Petrosino CFA +1.212.553.1946
VP-Senior Analyst
robert.petrosino@moodys.com

Nana Hamilton +1.212.553.9440
AVP-Analyst
nana.hamilton@moodys.com

Laura Schumacher +1.212.553.3853
VP-Sr Credit Officer
laura.schumacher@moodys.com

Jeffrey F. Cassella +1.212.553.1665
VP-Sr Credit Officer
jeffrey.cassella@moodys.com

Lesley Ritter +1.212.553.1607
AVP-Analyst
lesley.ritter@moodys.com

Jim Hempstead +1.212.553.4318
MD-Utilities
james.hempstead@moodys.com

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

» Contacts continued on last page

Regulated utilities - US

2019 outlook shifts to negative due to weaker cash flows, continued high leverage

Our negative outlook indicates our expectations for the fundamental business conditions driving the US regulated utility industry over the next 12-18 months.

The outlook for the US regulated utility sector has changed to negative from stable, reflecting increased financial risk due to lower cash flow and holding company leverage at its highest level since 2008. These factors will reduce the ratio of funds from operations (FFO) to debt by up to 200 basis points over the next 12-18 months.

» **Cash flow will decline due to a lower contribution from deferred taxes.** The combination of the loss of bonus depreciation and a lower tax rate as a result of the Tax Cuts & Jobs Act (TCJA) means that utilities and their holding companies will lose some of the cash flow contribution from deferred taxes. Since 2010, deferred taxes have contributed around 14% of consolidated FFO, but we see this falling to around 8% through 2019. This will drive down the consolidated ratio of FFO to debt, for a peer group of 42 utility holding companies, from 17% toward 15% over the outlook period.

» **Regulatory and management responses may not improve financials until 2020.** Some state regulatory commissions have issued credit-supportive rate orders to offset reduced cash flow because of tax reform, and several holding companies are executing plans to strengthen their balance sheets. But it could take longer than 12-18 months before sector-wide financial metrics improve.

» **High leverage will persist due to growing capital spending and rising dividends.** For our peer group, consolidated debt to EBITDA of 5.1x in 2017 was at a 10-year high, and a consolidated debt to equity ratio of 1.5x was at its highest level since 2008. These leverage metrics will remain elevated given higher capital spending in 2018 and 2019, rising dividends and a continued heavy reliance on debt financing.

» **What could change our outlook** The outlook could return to stable if we expect the sector's financial profile to stabilize, even if that is at today's lower levels. A positive outlook could be considered if we expect a recovery in key cash flow metrics where consolidated cash flow starts to improve by roughly 15%-20% or the ratio of consolidated FFO to debt indicates a return to the 17%-19% range. Underpinning each of these scenarios is a supportive regulatory environment across most US jurisdictions.

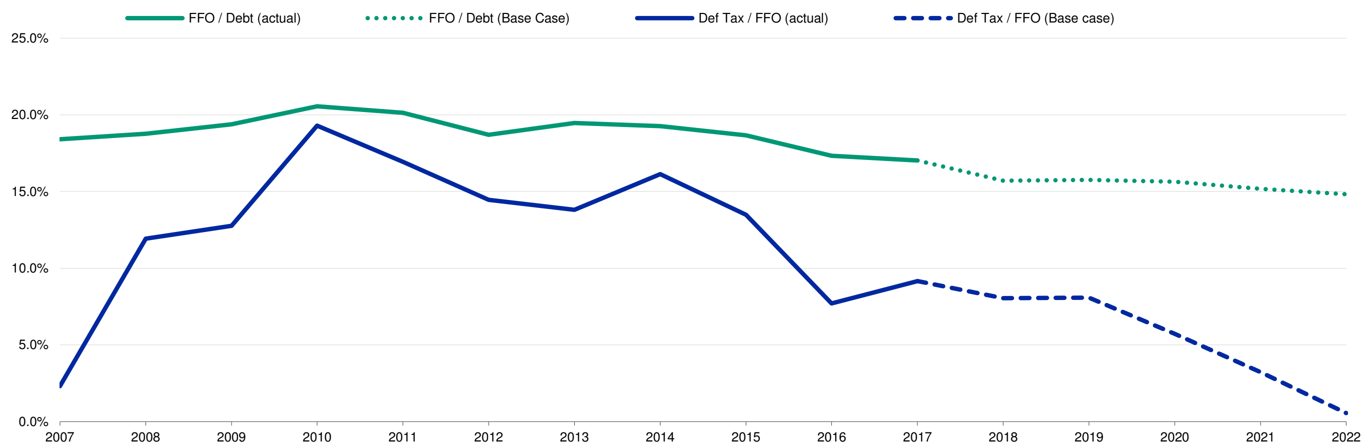
Cash flow will decline due to a lower contribution from deferred taxes

The combination of a lower tax rate and the loss of bonus depreciation as a result of the federal Tax Cuts & Jobs Act (TCJA) in December 2017 means that utilities and their holding companies will lose some of the cash flow contribution from deferred taxes on an ongoing basis, as shown in Exhibit 1.

For nearly a decade, bonus depreciation has created large timing differences between the book and tax amounts that utility holding companies report and pay as tax expense, and has resulted in a very low cash tax payment rate for the sector. Consequently, virtually all of the revenue that utilities have collected from customers to cover tax expense has been retained by the company as deferred tax liabilities, rather than paid to the Internal Revenue Service in any given year. These deferred taxes have boosted cash flow measures[1] significantly, accounting for roughly 14% of consolidated FFO, on average, since 2010.

Now, with the reduction in the corporate tax rate to 21% from 35%, utilities will collect less revenue from customers (since their federal tax expense is lower) and retain less cash via deferred taxes. As a result, the deferred-tax contribution to consolidated FFO will fall to around 8% through 2019, from an average of 14% since 2010, based on our financial forecast using a peer group of 42 regulated utility holding companies with 10 years of historical data (see Appendix A for a listing of holding company peers and Appendix D for a description of our key forecast assumptions). We also see the same trend for a peer group of 102 utility operating companies with 10 years of historical data. This decline will drive consolidated FFO to debt metrics down toward 15% from 17% and operating company FFO to debt to 20% from 24% over the next 12-18 months. See Appendix B for a list of the 102 operating companies.

Exhibit 1
Consolidated FFO to debt will decline as a result of lower deferred taxes



Key assumption: Cash tax rates of 0% in 2018 and 2019, 5% in 2020, 10% in 2021 and 15% in 2022
Source: Moody's Investors Service

Because outlooks represent our forward-looking view on business conditions that factor into our ratings, a negative (positive) outlook suggests that negative (positive) rating actions are more likely on average. However, the industry outlook does not represent a sum of upgrades, downgrades or ratings under review, or an average of the rating outlooks of issuers in the industry, but rather our assessment of the main direction of business fundamentals within the overall industry.

The loss of bonus depreciation means that most companies will start paying cash tax earlier than under the previous law. Under the TCJA, utilities can claim less in depreciation expense for tax purposes and will have higher taxable income. Notwithstanding the change in law, we still expect holding companies to pay little or no cash tax in 2018 and 2019 because most have significant accumulated net operating losses driven by past claims of bonus depreciation, production tax credits from renewable generation or other tax offsets.

Lowering the tax rate also means that utilities will have over-collected for tax expenses in the past because they charged for future tax expense assuming a 35% tax rate. As utilities refund the excess collection to customers, cash flow will be reduced, with the decline likely spread over 20 years or more.

Regulatory and management responses may not improve financials until 2020

Regulatory commissions and utility management teams are taking important first steps in addressing increased financial risk, but we believe that it will take longer than 12-18 months for the majority of the sector to show any material financial improvement from such efforts.

There are two principal approaches for a utility seeking to take mitigating action against rising financial risk. The first option is to pursue financial relief from regulators, which we see most companies doing across the industry in response to tax reform. The second is "self-help," where management teams alter financial policies to improve cash flow or their balance sheet. These efforts could include cutting operating or capital costs, issuing equity, reducing debt, selling non-core assets or slowing dividend growth. Such strategies were popular during the early 2000s period known as "back to basics," when many companies shed unregulated and international assets, reduced debt and focused on strengthening core regulatory relationships.

Regulation addressing tax reform

So far, we have seen credit positive developments in some states in response to tax reform, described in the box below. Most of these measures are positive because they provide incremental cash flow that will be used to replace some of the cash lost due to tax reform.

Some regulatory commissions have allowed early tax reform relief

In Florida, the Florida Public Service Commission allowed several of the state's utilities including Florida Power & Light Company (A1 stable), Duke Energy Florida, LLC (A3 stable) and Tampa Electric Company (A3 stable) to use the bulk of customer refunds resulting from tax reform changes to offset rate increases for power restoration costs associated with the utilities' response to Hurricane Irma. Duke Energy Florida was also permitted to use a portion of the savings to accelerate the depreciation of existing coal plants.

In April, the Georgia Public Service Commission (GPSC) approved a tax reform settlement agreement allowing Georgia Power Company (A3 negative) to increase its authorized retail equity ratio, currently around 51%, to the utility's actual equity capitalization percentage or 55% (whichever is lower) until its next rate case filing, scheduled to be filed 1 July 2019.

In May, the Alabama Public Service Commission approved two supportive rate proposal requests by Alabama Power Company (A1 negative), including 1) a plan designed to improve the company's balance sheet and credit quality over time by gradually increasing its equity ratio to 55% by 2025 and 2) allowing up to $30 million of excess deferred tax liability deferrals to offset under-recovered fuel costs.

In Indiana, Northern Indiana Public Service Company (Baa1 stable) has reached a gas rate settlement that, if approved by the Indiana Utility Regulatory Commission, would defer the cash outflows associated with unprotected deferred tax liabilities until 2020.

While we expect very supportive regulatory outcomes in states such as Florida, Georgia and Alabama—three of the most credit-supportive regulatory environments in the US—other states will likely have more moderate allowances for increased rates and cash flow recovery in regard to tax reform. So far, many state commissions have provided for the 21% tax rate to be implemented into rates in 2018, but have said they will address the return of excess deferred tax liabilities to customers at a later date—under a separate proceeding or at the time of a utility's next general rate case. This adds a degree of uncertainty to the ultimate timing of any cash flow impact on the sector.

Management efforts to address financial risk

Many companies are executing plans to strengthen their balance sheets in the face of increased financial risk, including incremental equity issuances beyond their pre-tax reform plans, selling assets or modest capex reductions. Some of these actions are defensive measures brought about by tax reform, while others are reactions to developments such as funding acquisitions, regulatory and political uncertainties, large capital programs or natural disasters. Other companies, although faced with negative credit trends, are making no material changes to financial policies.

Exhibit 2 shows a list of selected holding companies with a negative outlook or ratings under review for downgrade, as well as their planned responses to deal with heightened financial risks or other negative credit conditions.

Exhibit 2

Management teams are pursuing different avenues to relieve financial and credit risk

Holding companies with a negative outlook and under review for downgrade (RUR-D) as of 18 June 2018

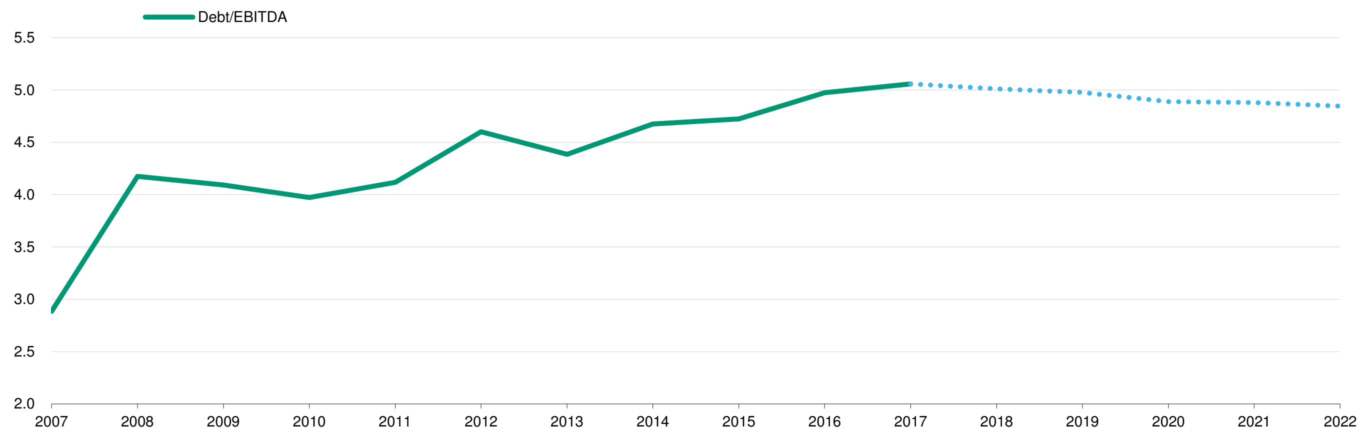
Company	Rating	Outlook	Pursuing Regulatory Relief for Tax Reform	Incremental Equity Issuance	Selling Assets	Incremental Capex Reduction	% of Annual Capex Reduced	Dividend Reduction
ALLETE, Inc.	A3	Negative	Yes	No	No	No	NA	No
Consolidated Edison, Inc.	A3	Negative	Yes	No	No	No	NA	No
Edison International	A3	Negative	Yes	No	No	No	NA	No
Integrys Holding, Inc.	A3	RUR-D	Yes	No	No	No	NA	No
OGE Energy Corp.	A3	Negative	Yes	No	No	No	NA	No
WEC energy Group, Inc.	A3	RUR-D	Yes	No	No	No	NA	No
WGL Holdings, Inc.	A3	Negative	Yes	No	No	No	NA	No
Alliant Energy Corporation	Baa1	Negative	Yes	No	No	No	NA	No
CenterPoint Energy, Inc.	Baa1	Negative	Yes	Yes	No	No	NA	No
Duke Energy Corporation	Baa1	Negative	Yes	Yes	No	Yes	2%	No
PG&E Corporation	Baa1	Negative	Yes	No	No	No	NA	Yes
Sempra Energy	Baa1	Negative	Yes	Yes	Yes	No	NA	No
Dominion Energy, Inc.	Baa2	Negative	Yes	Yes	Yes	Yes	11%	No
Entergy Corporation	Baa2	Negative	Yes	Yes	No	No	NA	No
Southern Company (The)	Baa2	Negative	Yes	Yes	Yes	No	NA	No
Cleco Corporate Holdings LLC	Baa3	RUR-D	Yes	No	No	No	NA	No
Emera Inc.	Baa3	Negative	Yes	Yes	No	No	NA	No
SCANA Corporation	Ba1	RUR-D	Yes	No	No	No	NA	No

Source: Company announcements and Moody's Investors Service

High leverage will persist because of significant capital spending and rising dividends

With roughly $600 billion of adjusted debt at year-end 2017, our peer group of 42 utility holding companies are exhibiting a 10-year high consolidated ratio of debt to EBITDA (5.1x in 2017) and the highest consolidated debt to equity ratio (1.5x in 2017) since 2008, the height of the financial crisis. As shown in Exhibit 3, these leverage ratios will remain elevated amid higher capital spending in 2018 and in 2019, rising dividends, and a continued heavy reliance on debt financing for negative free cash flow.

Exhibit 3
The ratio of debt to EBITDA for utility holding companies will likely remain at 10-year highs

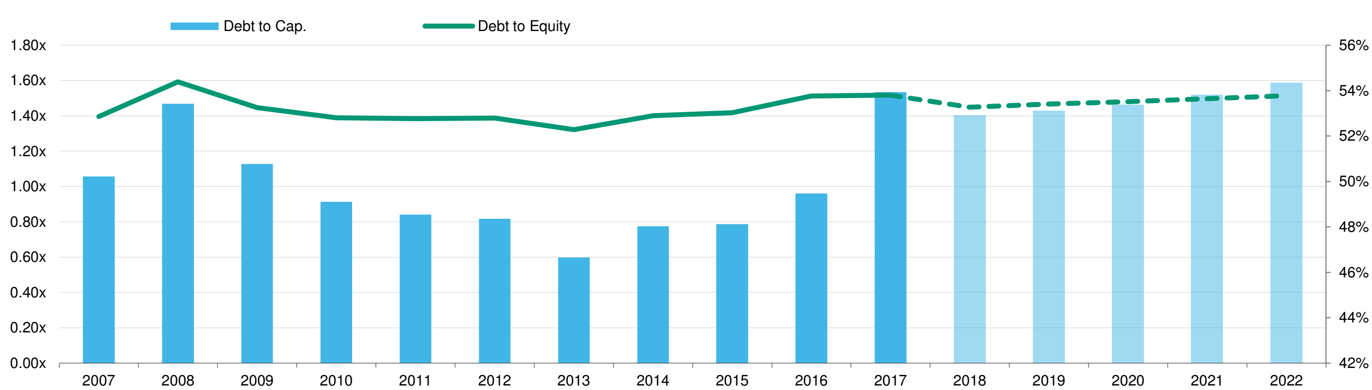


Source: Moody's Investors Service

Because of the lower tax rate, deferred tax liabilities were reduced, which negatively impacts our adjusted capitalization ratios. The deferred tax revaluation has increased the adjusted debt to capitalization ratio to 54% in 2017, from 49% in 2016, since it reduces the amount of total capitalization (debt + equity + deferred taxes) and reclassifies the excess deferred tax liabilities as a long-term regulatory liability owed to customers.

As Exhibit 4 shows, leverage is expected to remain high compared with historical levels, despite a significant amount of equity being issued in 2018. In 2018 we made a simplifying assumption that $20 billion of equity would be issued, offsetting a similar amount of debt that would otherwise have been used to fund negative free cash flow. That assumption acknowledges that several companies have announced equity issuances in 2018, including Duke Energy Corporation (Baa1 negative), Dominion Energy, Inc. (Baa2 negative) and Entergy Corporation (Baa2 negative). Without this equity, the ratio of debt to capitalization would have been 55% through 2022 and debt to equity would have been 1.5x, trending to 1.6x in 2022.

Exhibit 4
Despite equity issuance in 2018, leverage metrics will remain much higher than historical levels
Debt to Cap. (%) and Debt to Equity (x)



Source: Moody's Investors Service

Holding company leverage has been increasing in recent years due to factors such as highly levered mergers and acquisitions, investments in non-regulated activities including renewable energy portfolios and midstream ventures, and using holding company debt as a source for equity infusions into operating subsidiaries. We do not incorporate unregulated investment into our forecast scenarios, but we still see increasing debt levels because of high capital investments and rising dividends.

Capital spending is likely to increase

Utility companies continue to spend significant capital on their rate base through smart-grid investments, system resilience measures and carbon transition efforts, including renewable generation assets. This is likely to keep spending levels high for the next several years. A trend of higher capital spending could also ensue if companies see the revenue reduction from tax reform, and the consequent reduction in customer bills, as an opportunity to make additional capital investments that could be recovered in rates without increasing customer bills above their pre-tax reform levels.

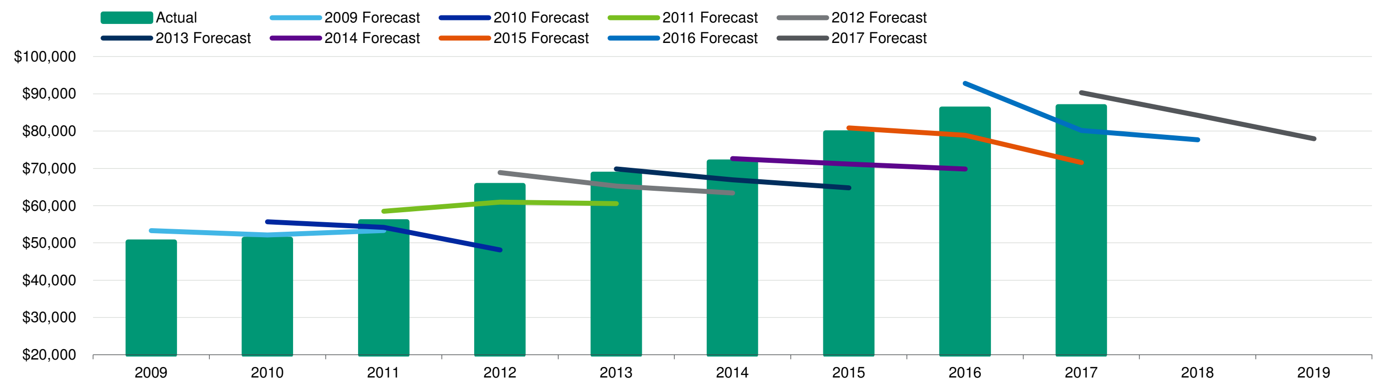
While many companies are estimating a steady decline in capital spending after 2018, our base-case projections assume that their capital spending will continue to increase, at about 5.0% each year, compared with a 2012-2017 compound annual growth rate (CAGR) of 5.7%.

As Exhibit 5 shows, while companies often project a downward trajectory in capital spending, the level of capital actually deployed frequently exceeds projections by a wide margin. In fact, for 25 holding companies that have reported 3-year capex projections since 2009 (see Appendix C for a list of companies), aggregate capital spending has always increased despite projections that usually predict a declining trend.

Exhibit 5

Utility capital spending is often projected to decline, but has actually grown annually since 2009

Annual 3-year capex projections for 25 regulated utility holding companies



Source: SPGMI

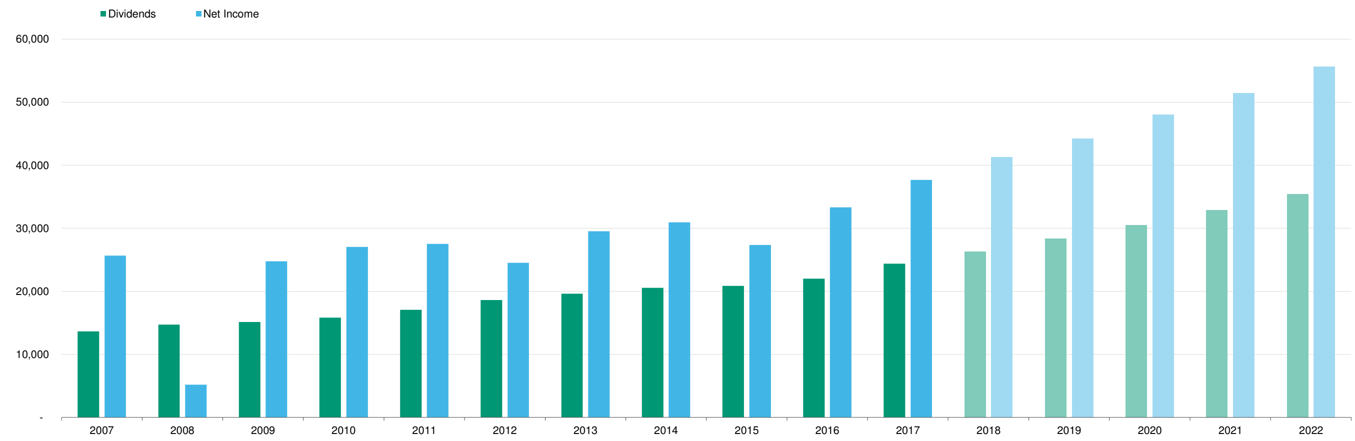
Dividends will continue to rise

As shown in Exhibit 6, we also expect that dividends will continue to increase, consistent with 2018 earnings call guidance indicating that payout policies are either unchanged or growing. In our base case forecast, we assume dividends increase at 8% year-over-year, which is the same growth rate as shown by net income.

Exhibit 6

The 10-year trend of increasing overall dividends is likely to continue through 2022

Actual dividends/net income (dark green/blue) and projected dividends/net income (light green/blue)



Source: Moody's Investors Service

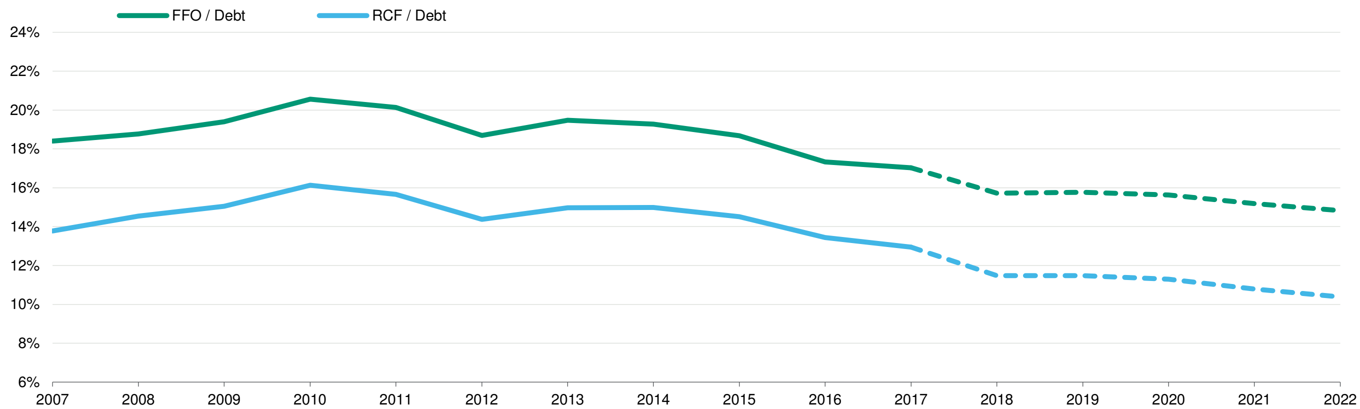
What could change our outlook

Stable outlook

The outlook could return to stable if we expect that the sector's financial profile will stabilize at today's lower levels, with consolidated FFO to debt metrics remaining steady. Exhibit 7 shows such stability could happen as early as 2019, with both FFO to debt and retained cash flow (RCF) to debt remaining between 15%-16% and 11%-12%, respectively, through year-end 2020.

Exhibit 7

A stable financial trend could emerge in 2019-2020 if cash flow growth keeps pace with debt



Key assumption: Cash tax rates of 0% in 2018 and 2019, 5% in 2020, 10% in 2021 and 15% in 2022

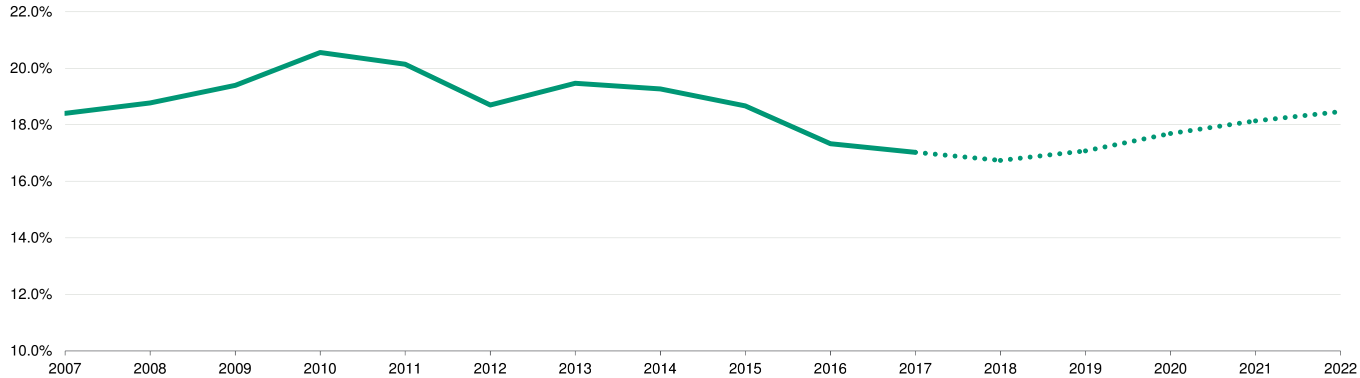
Source: Moody's Investors Service

We ran alternative scenarios to our base case forecast, including an upside case that assumes an improved financial performance by utilities and a downside case that assumes additional financial challenges.

Positive outlook

A positive outlook would be possible if we expect a recovery in key cash flow metrics, such as consolidated FFO to debt returning to the 17%-19% range. This is the case in our upside projection scenario, which reflects a greater use of equity funding of negative free cash flow and very strong recovery provisions allowed by regulators. In Exhibit 8, we assumed a 5% annual decline in capital spending after 2019, simulating the downward trend in industry-reported projections.

Exhibit 8
The sector outlook could change to positive if FFO to debt rebounds as projected in our upside case
Actual historical FFO to debt (solid line) and as-projected in our upside case (dotted line)

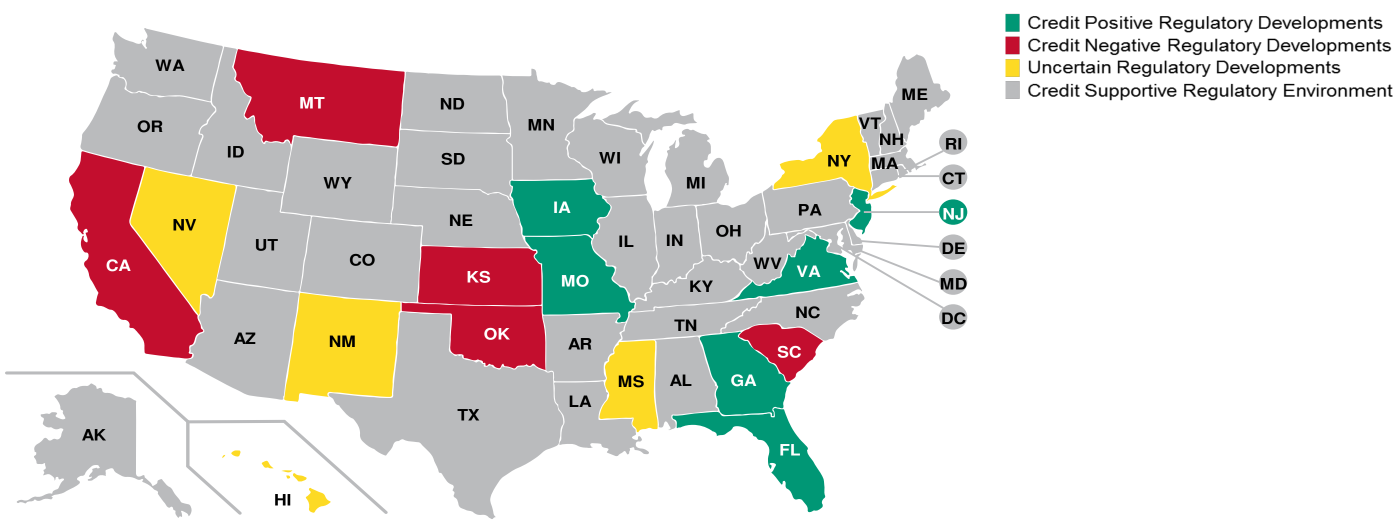


Source: Moody's Investors Service

Most state regulatory environments remain steadily supportive of credit

The underpinning of the sector outlook potentially returning to stable or changing to positive is a supportive regulatory environment. Exhibit 9 shows that, even today, most state jurisdictions remain predictably supportive of utility credit (grey), while some states have regulatory or legislative developments that could have positive (green), negative (red) or uncertain (yellow) impacts on utility credit.

Exhibit 9
Regulatory developments in most states continue to be stable and supportive of credit



Source: Moody's Investors Service

Appendix A - Holding company peer group

Exhibits 10 and 11 list the 42 regulated utility holding companies from which financial figures were derived by aggregating the annual data from 2007-2017 and applying key assumptions (see Appendix D) to drive our forecast scenarios. These companies were selected based on having ten years of historical data.

Exhibit 10

Companies 1-22 of 42 holding companies, sorted by highest to lowest consolidated CFO / Debt
$ in millions, as of the last twelve months available

Issuer	Rating and Outlook	CFO	Total Debt	CFO / Debt	Equity	Capex	Dividends
PG&E Corporation	Baa1 Negative	$ 5,908	$ 21,352	28%	$ 19,576	$ 5,900	$ 766
ALLETE, Inc.	A3 Negative	$ 465	$ 1,747	27%	$ 2,088	$ 275	$ 111
OGE Energy Corp.	A3 Negative	$ 851	$ 3,346	25%	$ 3,800	$ 728	$ 254
Edison International	A3 Negative	$ 3,749	$ 15,920	24%	$ 12,692	$ 4,072	$ 790
Vectren Utility Holdings, Inc.	A2 Stable	$ 419	$ 1,816	23%	$ 1,766	$ 569	$ 125
Ameren Corporation	Baa1 Stable	$ 2,040	$ 9,477	22%	$ 7,230	$ 2,264	$ 441
Pinnacle West Capital Corporation	A3 Stable	$ 1,205	$ 5,661	21%	$ 5,005	$ 1,439	$ 295
WEC Energy Group, Inc.	A3 Rating(s) Under Review	$ 2,292	$ 10,809	21%	$ 10,067	$ 2,080	$ 679
Public Service Enterprise Group Incorporated	Baa1 Stable	$ 3,053	$ 14,503	21%	$ 14,006	$ 4,049	$ 879
NextEra Energy, Inc.	Baa1 Stable	$ 6,437	$ 31,715	20%	$ 33,116	$ 9,035	$ 2,040
IDACORP, Inc.	Baa1 Stable	$ 440	$ 2,178	20%	$ 2,267	$ 281	$ 113
Exelon Corporation	Baa2 Stable	$ 8,073	$ 40,215	20%	$ 30,241	$ 7,612	$ 1,274
WGL Holdings, Inc.	A3 Negative	$ 505	$ 2,683	19%	$ 1,733	$ 466	$ 105
CMS Energy Corporation	Baa1 Stable	$ 1,782	$ 9,930	18%	$ 4,535	$ 1,739	$ 382
CenterPoint Energy, Inc.	Baa1 Negative	$ 1,635	$ 9,253	18%	$ 4,857	$ 1,485	$ 466
Evergy, Inc.	Baa2 Stable	$ 879	$ 4,980	18%	$ 4,920	$ 595	$ 257
DTE Energy Company	Baa1 Stable	$ 2,414	$ 13,894	17%	$ 10,064	$ 2,266	$ 659
American Electric Power Company, Inc.	Baa1 Stable	$ 4,413	$ 25,446	17%	$ 18,391	$ 6,505	$ 1,207
Consolidated Edison, Inc.	A3 Negative	$ 3,261	$ 18,992	17%	$ 15,514	$ 3,701	$ 814
Pepco Holdings, LLC	Baa2 Stable	$ 1,068	$ 6,267	17%	$ 9,488	$ 1,367	$ 313
PNM Resources, Inc.	Baa3 Positive	$ 493	$ 3,048	16%	$ 1,689	$ 524	$ 80
Puget Energy, Inc.	Baa3 Stable	$ 974	$ 6,066	16%	$ 3,649	$ 1,087	$ 153

Source: Moody's Investors Service

Appendix A (continued) - Holding company peer group

Exhibit 11

Companies 23-42 of 42 holding companies, sorted by highest to lowest consolidated CFO / Debt

$ in millions, as of the last twelve months available

Issuer	Rating and Outlook	CFO	Total Debt	CFO / Debt	Equity	Capex	Dividends
Hawaiian Electric Industries, Inc.	WR Stable	$ 418	$ 2,614	16%	$ 2,117	$ 546	$ 137
Berkshire Hathaway Energy Company	A3 Stable	$ 6,287	$ 42,392	15%	$ 28,667	$ 4,886	$ -
TECO Energy, Inc.	Baa2 Stable	$ 624	$ 4,276	15%	$ 2,879	$ 709	$ -
Black Hills Corporation	Baa2 Stable	$ 483	$ 3,331	15%	$ 1,871	$ 338	$ 101
Alliant Energy Corporation	Baa1 Negative	$ 873	$ 6,036	14%	$ 4,217	$ 1,520	$ 284
Entergy Corporation	Baa2 Negative	$ 2,909	$ 20,475	14%	$ 7,806	$ 3,940	$ 634
Spire Inc.	Baa2 Stable	$ 400	$ 2,872	14%	$ 2,138	$ 474	$ 102
Southern Company (The)	Baa2 Negative	$ 7,220	$ 52,269	14%	$ 26,339	$ 9,251	$ 2,505
SCANA Corporation	Ba1 Rating(s) Under Review	$ 956	$ 7,189	13%	$ 5,305	$ 1,114	$ 349
PPL Corporation	Baa2 Stable	$ 2,990	$ 22,682	13%	$ 11,409	$ 3,287	$ 1,098
Sempra Energy	Baa1 Negative	$ 3,627	$ 28,450	13%	$ 15,532	$ 3,994	$ 904
Duke Energy Corporation	Baa1 Negative	$ 6,849	$ 55,677	12%	$ 41,554	$ 8,043	$ 2,455
Eversource Energy	Baa1 Stable	$ 1,906	$ 15,542	12%	$ 11,219	$ 2,440	$ 615
Duquesne Light Holdings, Inc.	Baa3 Stable	$ 318	$ 2,596	12%	$ 1,078	$ 300	$ 103
Dominion Energy, Inc.	Baa2 Negative	$ 4,329	$ 38,692	11%	$ 18,857	$ 5,436	$ 2,050
NiSource Inc.	Baa2 Stable	$ 1,008	$ 9,429	11%	$ 4,435	$ 1,791	$ 238
FirstEnergy Corp.	Baa3 Stable	$ 2,247	$ 22,839	10%	$ 8,470	$ 3,002	$ 672
Cleco Corporate Holdings LLC	Baa3 Rating(s) Under Review	$ 287	$ 2,929	10%	$ 2,070	$ 252	$ 75
DPL Inc.	Ba2 Positive	$ 157	$ 1,692	9%	$ (536)	$ 107	$ -
IPALCO Enterprises, Inc.	Baa3 Stable	$ 253	$ 2,747	9%	$ 564	$ 179	$ 107

Source: Moody's Investors Service

Appendix B - Operating company peer group

Exhibits 12-15 list 102 operating companies that were analyzed as part of our financial comparisons. These companies were selected based on having ten years of historical data. Our base case scenario shows the aggregate cash flow to debt ratios of these companies dropping by 400 basis points over the next 12-18 months.

Exhibit 12

Companies 1-30 of 102 operating companies, sorted by highest to lowest CFO / Debt

$ in millions, as of the last twelve months available

Issuer	Rating and Outlook	CFO	Total Debt	CFO / Debt	Capex	Dividends
Metropolitan Edison Company	A3 Stable	$ 458	$ 1,060	43%	$ 152	$ 80
Atmos Energy Corporation	A2 Stable	$ 1,095	$ 3,371	32%	$ 1,300	$ 203
Southern California Gas Company	A1 Stable	$ 1,299	$ 4,111	32%	$ 1,433	$ 1
Baltimore Gas and Electric Company	A3 Stable	$ 945	$ 3,029	31%	$ 921	$ 199
Pennsylvania Power Company	Baa1 Stable	$ 64	$ 217	30%	$ 51	$ 20
Gulf Power Company	A2 Stable	$ 420	$ 1,420	30%	$ 235	$ 175
Tampa Electric Company	A3 Stable	$ 744	$ 2,530	29%	$ 660	$ 324
Duquesne Light Company	A3 Stable	$ 387	$ 1,321	29%	$ 282	$ 90
Madison Gas and Electric Company	A1 Stable	$ 136	$ 473	29%	$ 131	$ 32
Spire Alabama Inc.	A2 Stable	$ 136	$ 476	29%	$ 121	$ 32
Wisconsin Public Service Corporation	A2 Stable	$ 414	$ 1,465	28%	$ 363	$ 120
Kentucky Utilities Co.	A3 Stable	$ 690	$ 2,460	28%	$ 496	$ 235
Pacific Gas & Electric Company	A3 Negative	$ 5,860	$ 21,051	28%	$ 5,931	$ 542
Florida Power & Light Company	A1 Stable	$ 3,764	$ 13,562	28%	$ 4,728	$ 1,050
Consumers Energy Company	(P)A2 Stable	$ 1,865	$ 6,734	28%	$ 1,702	$ 494
Indiana Gas Company, Inc.	A2 Stable	$ 159	$ 574	28%	$ 209	$ -
Tucson Electric Power Company	A3 Stable	$ 435	$ 1,596	27%	$ 401	$ 70
Southern California Edison Company	A2 Negative	$ 3,777	$ 13,937	27%	$ 3,981	$ 657
Puget Sound Energy, Inc.	Baa1 Stable	$ 1,120	$ 4,136	27%	$ 1,036	$ 262
Northern States Power Company (Minnesota)	A2 Stable	$ 1,425	$ 5,296	27%	$ 920	$ 516
New Jersey Natural Gas Company	Aa2 Negative	$ 205	$ 764	27%	$ 185	$ 68
Louisville Gas & Electric Company	A3 Stable	$ 529	$ 2,021	26%	$ 527	$ 139
PPL Electric Utilities Corporation	A3 Stable	$ 937	$ 3,583	26%	$ 1,224	$ 332
Entergy New Orleans, Inc.	Ba1 Stable	$ 139	$ 533	26%	$ 130	$ 69
Ohio Power Company	A2 Stable	$ 655	$ 2,539	26%	$ 634	$ 178
MidAmerican Energy Company	A1 Stable	$ 1,391	$ 5,529	25%	$ 1,887	$ -
San Diego Gas & Electric Company	A1 Negative	$ 1,566	$ 6,246	25%	$ 1,613	$ 275
Oklahoma Gas & Electric Company	A1 Negative	$ 783	$ 3,121	25%	$ 727	$ 105
Southwestern Public Service Company	Baa1 Negative	$ 495	$ 1,988	25%	$ 555	$ 105
Central Hudson Gas & Electric Corporation	A2 Stable	$ 156	$ 636	24%	$ 171	$ 9

Source: Moody's Investors Service

Exhibit 13

Companies 31-60 of 102 operating companies, sorted by highest to lowest CFO / Debt

$ in millions, as of the last twelve months available

Issuer	Rating and Outlook		CFO		Total Debt	CFO / Debt		Capex		Dividends
Northern Illinois Gas Company	A2 Stable	$	284	$	1,205	24%	$	601	$	70
Questar Gas Company	A2 Negative	$	192	$	819	23%	$	231	$	-
Arizona Public Service Company	A2 Stable	$	1,229	$	5,280	23%	$	1,410	$	324
Black Hills Power, Inc.	A3 Stable	$	81	$	351	23%	$	75	$	-
Public Service Company of Colorado	A3 Stable	$	1,166	$	5,075	23%	$	1,593	$	336
Alabama Power Company	A1 Negative	$	1,883	$	8,204	23%	$	2,192	$	734
Duke Energy Carolinas, LLC	A1 Stable	$	2,510	$	10,995	23%	$	2,575	$	700
Sierra Pacific Power Company	Baa1 Stable	$	272	$	1,194	23%	$	193	$	43
Connecticut Natural Gas Corporation	A3 Stable	$	55	$	245	23%	$	64	$	7
Avista Corp.	Baa1 Negative	$	447	$	1,993	22%	$	407	$	94
UGI Utilities, Inc.	A2 Stable	$	256	$	1,144	22%	$	328	$	63
Piedmont Natural Gas Company, Inc.	A2 Negative	$	500	$	2,254	22%	$	559	$	-
Union Electric Company	Baa1 Stable	$	1,008	$	4,554	22%	$	883	$	355
Rochester Gas & Electric Corporation	A3 Stable	$	237	$	1,077	22%	$	279	$	-
Orange and Rockland Utilities, Inc.	A3 Negative	$	224	$	1,019	22%	$	198	$	45
Nevada Power Company	Baa1 Stable	$	694	$	3,178	22%	$	283	$	473
DTE Electric Company	A2 Stable	$	1,639	$	7,513	22%	$	1,560	$	439
Portland General Electric Company	A3 Stable	$	603	$	2,766	22%	$	520	$	118
Wisconsin Power and Light Company	A2 Negative	$	456	$	2,098	22%	$	607	$	129
Duke Energy Indiana, LLC.	A2 Stable	$	926	$	4,279	22%	$	902	$	300
PacifiCorp	A3 Stable	$	1,586	$	7,337	22%	$	839	$	750
PECO Energy Company	A2 Stable	$	680	$	3,192	21%	$	756	$	507
Duke Energy Kentucky, Inc.	Baa1 Stable	$	103	$	487	21%	$	222	$	-
Mississippi Power Company	Ba1 Positive	$	453	$	2,153	21%	$	249	$	(1)
Northern States Power Company (Wisconsin)	A2 Stable	$	172	$	825	21%	$	220	$	69
Westar Energy, Inc.	Baa1 Stable	$	957	$	4,602	21%	$	778	$	228
Otter Tail Power Company	A3 Stable	$	125	$	603	21%	$	121	$	40
Public Service Company of New Hampshire	A3 Stable	$	287	$	1,393	21%	$	313	$	155
Public Service Electric and Gas Company	A2 Stable	$	1,829	$	8,914	21%	$	2,848	$	-
United Illuminating Company	Baa1 Stable	$	234	$	1,154	20%	$	167	$	125

Source: Moody's Investors Service

Appendix B (continued) - Operating company peer group

Exhibit 14

Companies 61-90 of 102 operating companies, sorted by highest to lowest CFO / Debt

$ in millions, as of the last twelve months available

Issuer	Rating and Outlook	CFO	Total Debt	CFO / Debt	Capex	Dividends
Spire Missouri Inc.	A1 Stable	$ 267	$ 1,329	20%	$ 294	$ 14
NSTAR Electric Company	A2 Stable	$ 696	$ 3,489	20%	$ 757	$ 378
Delmarva Power & Light Company	Baa1 Stable	$ 324	$ 1,624	20%	$ 421	$ 118
Cleco Power LLC	A3 Stable	$ 305	$ 1,574	19%	$ 242	$ 128
CenterPoint Energy Houston Electric, LLC	A3 Stable	$ 985	$ 5,102	19%	$ 895	$ 180
Dayton Power & Light Company	Baa3 Positive	$ 134	$ 697	19%	$ 91	$ (96)
Virginia Electric and Power Company	A2 Stable	$ 2,562	$ 13,409	19%	$ 2,607	$ 908
Public Service Company of New Mexico	Baa2 Positive	$ 365	$ 1,937	19%	$ 324	$ 61
Washington Gas Light Company	A1 Negative	$ 279	$ 1,487	19%	$ 349	$ 87
Kansas City Power & Light Company	Baa1 Stable	$ 674	$ 3,592	19%	$ 463	$ 215
Oncor Electric Delivery Company LLC	A2 Stable	$ 1,541	$ 8,234	19%	$ 1,678	$ 151
El Paso Electric Company	Baa1 Negative	$ 284	$ 1,525	19%	$ 242	$ 54
Southern Indiana Gas & Electric Company	A2 Stable	$ 157	$ 849	19%	$ 154	$ 55
Appalachian Power Company	Baa1 Stable	$ 828	$ 4,486	18%	$ 828	$ 130
Georgia Power Company	A3 Negative	$ 2,180	$ 11,808	18%	$ 2,942	$ 1,302
Potomac Electric Power Company	Baa1 Stable	$ 502	$ 2,717	18%	$ 614	$ 128
Duke Energy Progress, LLC	A2 Stable	$ 1,489	$ 8,329	18%	$ 1,701	$ 124
Texas-New Mexico Power Company	A3 Stable	$ 93	$ 524	18%	$ 162	$ 36
Public Service Company of Oklahoma	A3 Negative	$ 286	$ 1,606	18%	$ 248	$ 65
Connecticut Light and Power Company	Baa1 Rating(s) Under Review	$ 703	$ 3,977	18%	$ 855	$ 268
Public Service Co. of North Carolina, Inc.	A3 Rating(s) Under Review	$ 131	$ 740	18%	$ 289	$ 41
Consolidated Edison Company of New York, Inc.	A2 Negative	$ 2,743	$ 15,877	17%	$ 3,190	$ 808
Hawaiian Electric Company, Inc.	Baa2 Stable	$ 340	$ 2,007	17%	$ 475	$ 94
DTE Gas Company	A2 Negative	$ 286	$ 1,692	17%	$ 434	$ 106
CenterPoint Energy Resources Corp.	Baa2 Stable	$ 492	$ 2,918	17%	$ 537	$ 579
Entergy Arkansas, Inc.	Baa1 Stable	$ 637	$ 3,780	17%	$ 798	$ 16
Northwest Natural Gas Company	A3 Negative	$ 183	$ 1,093	17%	$ 235	$ 53
Duke Energy Ohio, Inc.	Baa1 Positive	$ 418	$ 2,502	17%	$ 734	$ 25
Atlantic City Electric Company	Baa2 Positive	$ 219	$ 1,338	16%	$ 299	$ 67
Southwestern Electric Power Company	Baa2 Stable	$ 475	$ 2,923	16%	$ 472	$ 116

Source: Moody's Investors Service

Appendix B (continued) - Operating company peer group

Exhibit 15

Companies 91-102 of 102 operating companies, sorted by highest to lowest CFO / Debt

$ in millions, as of the last twelve months available

Issuer	Rating and Outlook	CFO	Total Debt	CFO / Debt	Capex	Dividends
Idaho Power Company	A3 Stable	$ 386	$ 2,418	16%	$ 274	$ 115
Entergy Mississippi, Inc.	Baa1 Stable	$ 239	$ 1,513	16%	$ 412	$ 26
Entergy Texas, Inc.	Baa3 Stable	$ 257	$ 1,627	16%	$ 369	$ -
NorthWestern Corporation	Baa2 Stable	$ 339	$ 2,166	16%	$ 277	$ 103
Wisconsin Electric Power Company	A2 Stable	$ 861	$ 5,665	15%	$ 685	$ 241
Commonwealth Edison Company	A3 Stable	$ 1,436	$ 9,489	15%	$ 2,163	$ 434
Berkshire Gas Company	A3 Positive	$ 10	$ 68	14%	$ 17	$ -
Duke Energy Florida, LLC.	A3 Stable	$ 1,072	$ 7,577	14%	$ 1,256	$ -
South Carolina Electric & Gas Company	Baa3 Rating(s) Under Review	$ 754	$ 5,504	14%	$ 813	$ 322
Kentucky Power Company	Baa2 Negative	$ 129	$ 946	14%	$ 110	$ 26
Interstate Power and Light Company	Baa1 Negative	$ 338	$ 2,834	12%	$ 756	$ 154
South Jersey Gas Company	A2 Negative	$ 99	$ 994	10%	$ 246	$ 20

Source: Moody's Investors Service

Appendix C - Holding company capital spending peer group

The 25 holding companies incorporated into Exhibit 5 were selected based upon having 3-year publicly disclosed capital spending projections since in every year since 2009 and being a part of our larger 42 holding company peer group. Those companies are listed in Exhibit 16 below, sorted by rating category.

Exhibit 16

Capital spending for 25 holding companies has increased, in aggregate, year-over-year since 2016
($ millions)

		Capital Expenditures					
		2016		2017		LTM Mar 18	
Consolidated Edison, Inc.	A3 Negative	$	3,898	$	3,703	$	3,701
Edison International	A3 Negative	$	3,790	$	3,879	$	4,072
OGE Energy Corporation	A3 Negative	$	660	$	810	$	728
Pinnacle West Capital Corporation	A3 Stable	$	1,289	$	1,424	$	1,439
Xcel Energy, Inc.	A3 Stable	$	3,225	$	3,238	$	3,363
Alliant Energy Corporation	Baa1 Negative	$	1,182	$	1,456	$	1,520
Ameren Corporation	Baa1 Stable	$	2,164	$	2,204	$	2,264
American Electric Power Company, Inc.	Baa1 Stable	$	5,039	$	5,945	$	6,505
CenterPoint Energy, Inc.	Baa1 Negative	$	1,423	$	1,435	$	1,485
CMS Energy Corporation	Baa1 Stable	$	1,689	$	1,682	$	1,739
DTE Energy Company	Baa1 Stable	$	2,082	$	2,294	$	2,266
PG&E Corporation	Baa1 Negative	$	5,662	$	5,646	$	5,900
Duke Energy Corporation	Baa1 Negative	$	8,089	$	8,116	$	8,043
Public Service Enterprise Group Inc.	Baa1 Stable	$	4,098	$	4,058	$	4,049
Sempra Energy	Baa1 Negative	$	4,153	$	3,951	$	3,994
Dominion Energy, Inc.	Baa2 Negative	$	6,054	$	5,768	$	5,436
Entergy Corporation	Baa2 Negative	$	4,005	$	3,900	$	3,940
Exelon Corporation	Baa2 Stable	$	8,672	$	7,741	$	7,612
Evergy, Inc.	Baa2 Stable	$	626	$	591	$	595
NiSource Inc.	Baa2 Stable	$	1,517	$	1,733	$	1,791
PPL Corporation	Baa2 Stable	$	2,999	$	3,210	$	3,287
Southern Company (The)	Baa2 Negative	$	7,537	$	8,940	$	9,251
FirstEnergy Corporation	Baa3 Stable	$	3,253	$	3,117	$	3,002
PNM Resources, Inc.	Baa3 Positive	$	622	$	521	$	524
SCANA Corporation	Ba1 Rating(s) Under Review	$	1,566	$	1,229	$	1,114
Group Total		**$**	**85,291**	**$**	**86,592**	**$**	**87,620**

Source: Company 10K filings, Moody's standard adjustments

Appendix D - 2018-2022 forecast assumptions

Key Base Case assumptions

- Projected numbers are based on the consolidated financials of a fully regulated utility holding company
- "Forward test year" (e.g., 2019 net income is derived from 2018 rate base plus 2019 capex less 2019 depreciation less 2019 deferred tax liability (DTL), adjusted for normalization of excess DTLs returned to customers)
- 50% equity layer used for rate making purposes, as opposed to the holding company capital structure that is roughly 60/40 debt/equity
- Cash tax rates: 2018- 0%, 2019- 0%, 2020- 5%, 2021- 10%, 2022- 15%
- Additional cash inflow from operations that exactly offsets the cash outflow due to normalized excess deferred tax liabilities returned to customers
- Capex - 5 year projected CAGR is 5.0% versus the 5 year historical CAGR of 5.7%
- Dividend growth is set to match Net Income growth, which is roughly 8% year-over-year
- $20 billion of equity issuance in 2018 to reflect holdco efforts to strengthen their balance sheets
- Funding percentage of negative free cash flow is 88/12 debt/equity; set to keep debt and equity CAGR equivalent at about 6%

Key differences in Upside Case assumptions

- 53% equity layer in rates
- Cash tax rates: 2018- 0%, 2019- 0%, 2020- 3%, 2021- 5%, 2022- 10%
- Regulators approve a cash inflow that is twice the size of the cash outflow due to normalized excess deferred tax liabilities returned to customers
- 2019 Capex is flat to 2018 and declines 5% year-over-year thereafter
- Funding percentage of negative free cash flow is 60/40 debt/equity (debt CAGR of 2%, equity CAGR of 7%)

Key differences in Downside Case assumptions

- 4% inflation on O&M, Taxes and Other OpEx
- Regulators approve a cash inflow that is half the size of the cash outflow due to normalized excess deferred tax liabilities returned to customers
- 7% Capex growth year-over-year
- Funding of negative free cash flow is 100% debt (debt CAGR of 7.8% vs. equity CAGR of 5.0%)

Moody's related publications

Sector In-Depth:

» Offshore Wind is Ready for Prime Time 29 March 2018

» Tax Reform is Credit Negative for Regulated Utilities Sector, but Impact Varies by Company 24 January 2018

» Cross-Sector – US: FAQ on the Credit Impact of New Tax Law 24 January 2018

» Cross-Sector – US: Corporate Tax Cut is Credit Positive, While Effects of Other Provisions Vary by Sector 21 December 2017

» Regulated Electric & Gas Utilities – US: Insulating Utilities from Parent Contagion Risk is Increasingly a Focus of Regulators 18 September 2017

» Renewable Energy - Global: Falling Cost of Renewables Reduces Risks to Paris Agreement Compliance 6 September 2017

» Renewable Energy – Global: Renewables Sector Risks Shift as Competition Reduces Reliance on Government Subsidy 6 September 2017

Rating Methodologies:

» Regulated Electric and Gas Utilities 23 June 2017

» Unregulated Utilities and Unregulated Power Companies 17 May 2017

» Regulated Electric and Gas Networks 16 March 2017

» U.S. Electric Generation & Transmission 15 April 2013

» Natural Gas Pipelines 6 November 2012

Endnotes

1 Our cash flow analysis consists of three primary measures, including: cash flow from operations (CFO), funds from operations (FFO) and CFO before changes in working capital. For purposes of this report we reference FFO due to our forecast scenarios' focus on Net Income, Depreciation and Deferred Taxes (including regulatory liabilities associated with deferred taxes).

REPORT NUMBER 1128302

Analyst Contacts

Toby Shea +1.212.553.1779
VP-Sr Credit Officer
toby.shea@moodys.com

Swami Venkataraman, CFA +1.212.553.7950
Senior Vice President
swami.venkat@moodys.com

Jairo Chung +1.212.553.5123
AVP-Analyst
jairo.chung@moodys.com

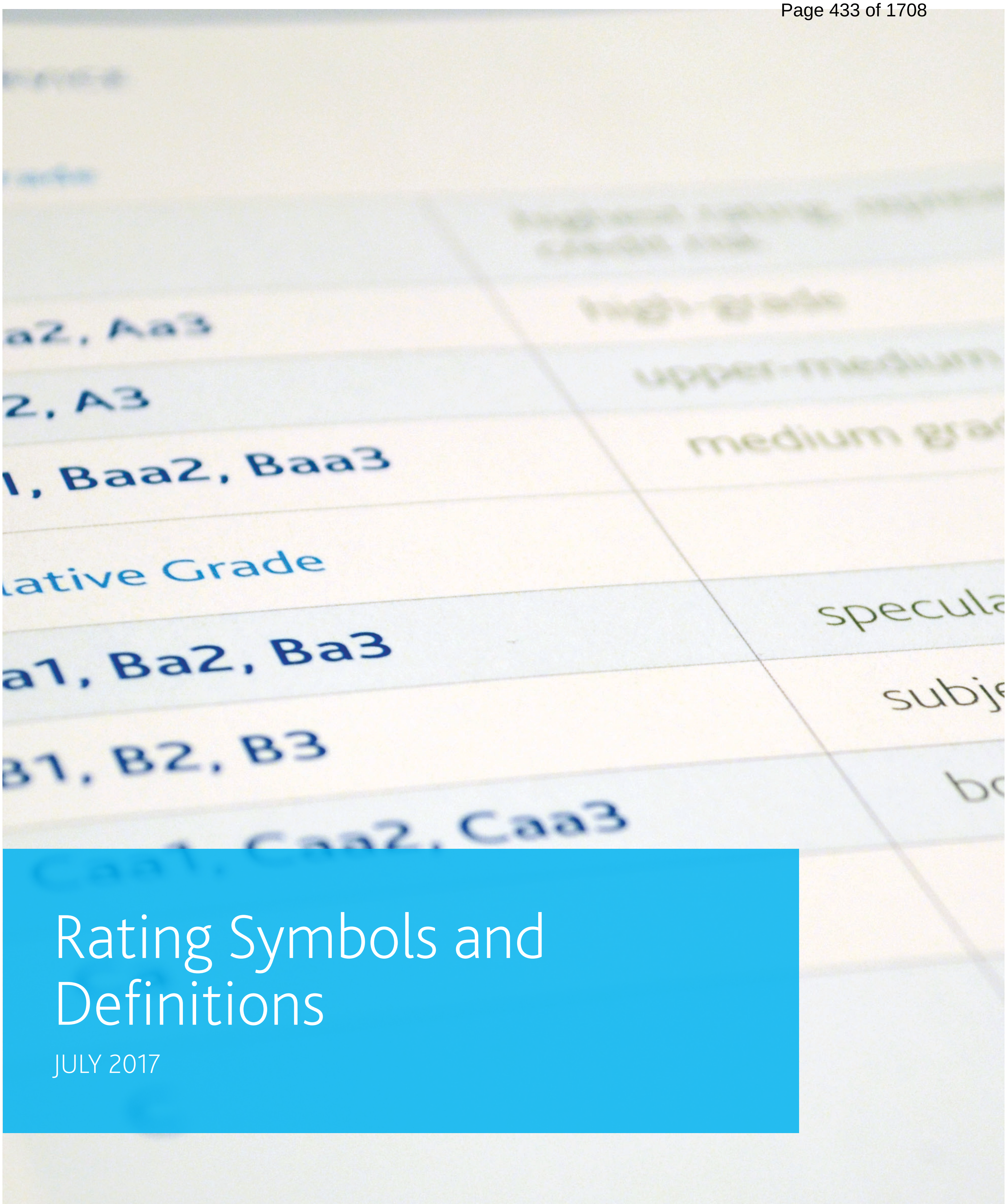
Gavin Macfarlane +1.416.214.3864
VP-Sr Credit Officer
gavin.macfarlane@moodys.com

Natividad Martel, CFA +1.212.553.4561
VP-Senior Analyst
natividad.martel@moodys.com

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MOODY'S
INVESTORS SERVICE



Rating Symbols and Definitions

JULY 2017

MOODY'S
INVESTORS SERVICE

Preface

In the spirit of promoting transparency and clarity, Moody's Standing Committee on Rating Symbols and Definitions offers this updated reference guide which defines Moody's various ratings symbols, rating scales and other ratings-related definitions.

Since John Moody devised the first bond ratings more than a century ago, Moody's rating systems have evolved in response to the increasing depth and breadth of the global capital markets. Much of the innovation in Moody's rating system is a response to market needs for clarity around the components of credit risk or to demands for finer distinctions in rating classifications.

I invite you to contact us with your comments.

Kenneth Emery
Chair, Standing Committee on Rating Symbols and Definitions
+1.212.553.4415
kenneth.emery@moodys.com

Contents

27

Other Definitions

Credit Rating Services

Moody's Global Rating Scales

Ratings assigned on Moody's global long-term and short-term rating scales are forward-looking opinions of the relative credit risks of financial obligations issued by non-financial corporates, financial institutions, structured finance vehicles, project finance vehicles, and public sector entities. Long-term ratings are assigned to issuers or obligations with an original maturity of one year or more and reflect both on the likelihood of a default on contractually promised payments and the expected financial loss suffered in the event of default. Short-term ratings are assigned to obligations with an original maturity of thirteen months or less and reflect both on the likelihood of a default on contractually promised payments and the expected financial loss suffered in the event of default.[1][2]

Moody's differentiates structured finance ratings from fundamental ratings (i.e., ratings on nonfinancial corporate, financial institution, and public sector entities) on the global long-term scale by adding (sf) to all structured finance ratings.[3] The addition of (sf) to structured finance ratings should eliminate any presumption that such ratings and fundamental ratings at the same letter grade level will behave the same. The (sf) indicator for structured finance security ratings indicates that otherwise similarly rated structured finance and fundamental securities may have different risk characteristics. Through its current methodologies, however, Moody's aspires to achieve broad expected equivalence in structured finance and fundamental rating performance when measured over a long period of time.

1 For certain structured finance, preferred stock and hybrid securities in which payment default events are either not defined or do not match investors' expectations for timely payment, long-term and short-term ratings reflect the likelihood of impairment (as defined below in this publication) and financial loss in the event of impairment.

2 Supranational institutions and central banks that hold sovereign debt or extend sovereign loans, such as the IMF or the European Central Bank, may not always be treated similarly to other investors and lenders with similar credit exposures. Long-term and short-term ratings assigned to obligations held by both supranational institutions and central banks, as well as other investors, reflect only the credit risks faced by other investors unless specifically noted otherwise.

3 Like other global scale ratings, (sf) ratings reflect both the likelihood of a default and the expected loss suffered in the event of default. Ratings are assigned based on a rating committee's assessment of a security's expected loss rate (default probability multiplied by expected loss severity), and may be subject to the constraint that the final expected loss rating assigned would not be more than a certain number of notches, typically three to five notches, above the rating that would be assigned based on an assessment of default probability alone. The magnitude of this constraint may vary with the level of the rating, the seasoning of the transaction, and the uncertainty around the assessments of expected loss and probability of default.

Global Long-Term Rating Scale

Aaa	Obligations rated Aaa are judged to be of the highest quality, subject to the lowest level of credit risk.
Aa	Obligations rated Aa are judged to be of high quality and are subject to very low credit risk.
A	Obligations rated A are judged to be upper-medium grade and are subject to low credit risk.
Baa	Obligations rated Baa are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.
Ba	Obligations rated Ba are judged to be speculative and are subject to substantial credit risk.
B	Obligations rated B are considered speculative and are subject to high credit risk.
Caa	Obligations rated Caa are judged to be speculative of poor standing and are subject to very high credit risk.
Ca	Obligations rated Ca are highly speculative and are likely in, or very near, default, with some prospect of recovery of principal and interest.
C	Obligations rated C are the lowest rated and are typically in default, with little prospect for recovery of principal or interest.

Note: Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category. Additionally, a "(hyb)" indicator is appended to all ratings of hybrid securities issued by banks, insurers, finance companies, and securities firms.*

Note: For more information on long-term ratings assigned to obligations in default, please see the definition "Long-Term Credit Ratings for Defaulted or Impaired Securities" in the Other Definitions section of this publication.

* *By their terms, hybrid securities allow for the omission of scheduled dividends, interest, or principal payments, which can potentially result in impairment if such an omission occurs. Hybrid securities may also be subject to contractually allowable write-downs of principal that could result in impairment. Together with the hybrid indicator, the long-term obligation rating assigned to a hybrid security is an expression of the relative credit risk associated with that security.*

Global Short-Term Rating Scale

P-1	Issuers (or supporting institutions) rated Prime-1 have a superior ability to repay short-term debt obligations.
P-2	Issuers (or supporting institutions) rated Prime-2 have a strong ability to repay short-term debt obligations.
P-3	Issuers (or supporting institutions) rated Prime-3 have an acceptable ability to repay short-term obligations.
NP	Issuers (or supporting institutions) rated Not Prime do not fall within any of the Prime rating categories.

Standard Linkage Between the Global Long-Term and Short-Term Rating Scales

The following table indicates the long-term ratings consistent with different short-term ratings when such long-term ratings exist.[4]

LONG-TERM RATING	SHORT-TERM RATING
Aaa, Aa1, Aa2, Aa3, A1, A2, A3	Prime-1
A3, Baa1	Prime-2
Baa2, Baa3	Prime-3
Ba1, Ba2, Ba3 B1, B2, B3 Caa1, Caa2, Caa3 Ca, C	Not Prime

Obligations and Issuers Rated on the Global Long-Term and Short-Term Rating Scales

Bank Deposit Ratings

Bank Deposit Ratings are opinions of a bank's ability to repay punctually its foreign and/or domestic currency deposit obligations and also reflect the expected financial loss of the default. Bank Deposit Ratings do not apply to deposits that are subject to a public or private insurance scheme; rather, the ratings apply to the most junior class of uninsured deposits, but they may in some cases incorporate the possibility that official support might in certain cases extend to the most junior class of uninsured as well as preferred and insured deposits. Foreign currency deposit ratings are subject to Moody's country ceilings for foreign currency deposits. This may result in the assignment of a different (and typically lower) rating for the foreign currency deposits relative to the bank's rating for domestic currency deposits.

Clearing Counterparty Ratings

A Clearing Counterparty Rating (CCR) reflects Moody's opinion of a Central Counterparty Clearing House's (CCP) ability to meet the timely clearing and settlement of clearing obligations by the CCP as well as the expected financial loss in the event the obligation is not fulfilled. A CCR can be assigned at a CCP legal entity or clearing service level to the extent a legal entity operates multiple clearing services.

Corporate Family Ratings

Moody's Corporate Family Ratings (CFRs) are long-term ratings that reflect the relative likelihood of a default on a corporate family's debt and debt-like obligations and the expected financial loss suffered in the event of default. A CFR is assigned to a corporate family as if it had a single class of debt and a single consolidated legal entity structure. CFRs are generally employed for speculative grade obligors, but may also be assigned to investment grade obligors. The CFR normally applies to all affiliates under the management control of the entity to which it is assigned. For financial institutions or other complex entities, CFRs may also be assigned to an association or group where the group may not exercise full management control, but where strong intra-group support and cohesion among individual group members may warrant a rating for the group or association. A CFR does not reference an obligation or class of debt and thus does not reflect priority of claim.

Credit Default Swap Ratings

Credit Default Swap Ratings measure the risk associated with the obligations that a credit protection provider has with respect to credit events under the terms of the transaction. The ratings do not address potential losses resulting from an early termination of the transaction, nor any market risk associated with the transaction.

Enhanced Ratings

Enhanced Ratings only pertain to US municipal securities. Enhanced ratings are assigned to obligations that benefit from third-party credit or liquidity support, including state aid intercept programs. They primarily reflect the credit quality of the support provider, and, in some cases, also reflect the credit quality of the underlying obligation. Enhanced ratings do not incorporate support based on insurance provided by financial guarantors.

4 Structured finance short-term ratings are usually based either on the short-term rating of a support provider or on an assessment of cash flows available to retire the financial obligation.

Insurance Financial Strength Ratings

Insurance Financial Strength Ratings are opinions of the ability of insurance companies to pay punctually senior policyholder claims and obligations and also reflect the expected financial loss suffered in the event of default. Specific obligations are considered unrated unless they are individually rated because the standing of a particular insurance obligation would depend on an assessment of its relative standing under those laws governing both the obligation and the insurance company.

Insured Ratings

An insured or wrapped rating is Moody's assessment of a particular obligation's credit quality given the credit enhancement provided by a financial guarantor. Moody's insured ratings apply a credit substitution methodology, whereby the debt rating matches the higher of (i) the guarantor's financial strength rating and (ii) any published underlying or enhanced rating on the security.

Issuer Ratings

Issuer Ratings are opinions of the ability of entities to honor senior unsecured debt and debt like obligations.[5] As such, Issuer Ratings incorporate any external support that is expected to apply to all current and future issuance of senior unsecured financial obligations and contracts, such as explicit support stemming from a guarantee of all senior unsecured financial obligations and contracts, and/or implicit support for issuers subject to joint default analysis (e.g. banks and government-related issuers). Issuer Ratings do not incorporate support arrangements, such as guarantees, that apply only to specific (but not to all) senior unsecured financial obligations and contracts.

While Issuer Ratings reflect the risk that debt and debt-like claims are not serviced on a timely basis, they do not reflect the risk that a contract or other non-debt obligation will be subjected to commercial disputes. Additionally, while an issuer may have senior unsecured obligations held by both supranational institutions and central banks (e.g., IMF, European Central Bank), as well as other investors, Issuer Ratings reflect only the risks faced by other investors.

Long-Term and Short-Term Obligation Ratings

Moody's assigns ratings to long-term and short-term financial obligations. Long-term ratings are assigned to issuers or obligations with an original maturity of one year or more and reflect both on the likelihood of a default on contractually promised payments and the expected financial loss suffered in the event of default. Short-term ratings are assigned to obligations with an original maturity of thirteen months or less and reflect both on the likelihood of a default on contractually promised payments and the expected financial loss suffered in the event of default.

Medium-Term Note Program Ratings

Moody's assigns provisional ratings to medium-term note (MTN) programs and definitive ratings to the individual debt securities issued from them (referred to as drawdowns or notes).

MTN program ratings are intended to reflect the ratings likely to be assigned to drawdowns issued from the program with the specified priority of claim (e.g. senior or subordinated). To capture the contingent nature of a program rating, Moody's assigns provisional ratings to MTN programs. A provisional rating is denoted by a (P) in front of the rating and is defined elsewhere in this document.

The rating assigned to a drawdown from a rated MTN or bank/deposit note program is definitive in nature, and may differ from the program rating if the drawdown is exposed to additional credit risks besides the issuer's default, such as links to the defaults of other issuers, or has other structural features that warrant a different rating. In some circumstances, no rating may be assigned to a drawdown.

Moody's encourages market participants to contact Moody's Ratings Desks or visit moodys.com directly if they have questions regarding ratings for specific notes issued under a medium-term note program. Unrated notes issued under an MTN program may be assigned an NR (not rated) symbol.

Structured Finance Counterparty Instrument Ratings

Structured Finance Counterparty Instrument Ratings are assigned to a financial contract and measure the risk posed to a counterparty arising from a special purpose vehicle's (SPV's) default with respect to its obligations under the referenced financial contract.

5 Issuer Ratings as applied to US local governments typically reflect an unlimited general obligation pledge, which may have security and structural features in some states that improve credit quality for general obligation bondholders, but not necessarily for other counterparties holding obligations that may lack such features.

Structured Finance Counterparty Ratings

Structured Finance Counterparty Ratings are assigned to structured financial operating companies and are founded upon an assessment of their ability and willingness to honor their obligations under financial contracts.

Structured Finance Interest Only Security (IO) Ratings

A structured finance IO is a stream of cash flows that is a fraction of the interest flows from one or multiple referenced securities or assets in a structured finance transaction. IO ratings address the likelihood and degree to which payments made to the IO noteholders will be impacted by credit losses to the security, securities or assets referenced by the IO. Such IO securities generally do not have a principal balance. Other non-credit risks, such as a prepayment of the referenced securities or assets, are not addressed by the rating, although they may impact payments made to the noteholders.

Underlying Ratings

An underlying rating is Moody's assessment of a particular obligation's credit quality absent any insurance or wrap from a financial guarantor or other credit enhancement.

For US municipal securities, the underlying rating will reflect the underlying issue's standalone credit quality absent any credit support provided by a state credit enhancement program.

US Municipal Short-Term Debt and Demand Obligation Ratings

Short-Term Obligation Ratings

While the global short-term 'prime' rating scale is applied to US municipal tax-exempt commercial paper, these programs are typically backed by external letters of credit or liquidity facilities and their short-term prime ratings usually map to the long-term rating of the enhancing bank or financial institution and not to the municipality's rating. Other short-term municipal obligations, which generally have different funding sources for repayment, are rated using two additional short-term rating scales (i.e., the MIG and VMIG scales discussed below).

The Municipal Investment Grade (MIG) scale is used to rate US municipal bond anticipation notes of up to three years maturity. Municipal notes rated on the MIG scale may be secured by either pledged revenues or proceeds of a take-out financing received prior to note maturity. MIG ratings expire at the maturity of the obligation, and the issuer's long-term rating is only one consideration in assigning the MIG rating. MIG ratings are divided into three levels—MIG 1 through MIG 3—while speculative grade short-term obligations are designated SG.

MIG Scale

MIG 1	This designation denotes superior credit quality. Excellent protection is afforded by established cash flows, highly reliable liquidity support, or demonstrated broad-based access to the market for refinancing.
MIG 2	This designation denotes strong credit quality. Margins of protection are ample, although not as large as in the preceding group.
MIG 3	This designation denotes acceptable credit quality. Liquidity and cash-flow protection may be narrow, and market access for refinancing is likely to be less well-established.
SG	This designation denotes speculative-grade credit quality. Debt instruments in this category may lack sufficient margins of protection.

Demand Obligation Ratings

In the case of variable rate demand obligations (VRDOs), a two-component rating is assigned: a long or short-term debt rating and a demand obligation rating. The first element represents Moody's evaluation of risk associated with scheduled principal and interest payments. The second element represents Moody's evaluation of risk associated with the ability to receive purchase price upon demand ("demand feature"). The second element uses a rating from a variation of the MIG scale called the Variable Municipal Investment Grade (VMIG) scale. VMIG ratings of demand obligations with unconditional liquidity support are mapped from the short-term debt rating (or counterparty assessment) of the support provider, or the underlying obligor in the absence of third party liquidity support, with VMIG 1 corresponding to P-1, VMIG 2 to P-2, VMIG 3 to P-3 and SG to not prime. For example, the VMIG rating for an industrial revenue bond with Company XYZ as the underlying obligor would normally have the same numerical modifier as Company XYZ's prime rating. Transitions of VMIG ratings of demand obligations with conditional liquidity support, as shown in the diagram below, differ from transitions on the Prime scale to reflect the risk that external liquidity support will terminate if the issuer's long-term rating drops below investment grade.

VMIG Scale

VMIG 1	This designation denotes superior credit quality. Excellent protection is afforded by the superior short-term credit strength of the liquidity provider and structural and legal protections that ensure the timely payment of purchase price upon demand.
VMIG 2	This designation denotes strong credit quality. Good protection is afforded by the strong short-term credit strength of the liquidity provider and structural and legal protections that ensure the timely payment of purchase price upon demand.
VMIG 3	This designation denotes acceptable credit quality. Adequate protection is afforded by the satisfactory short-term credit strength of the liquidity provider and structural and legal protections that ensure the timely payment of purchase price upon demand.
SG	This designation denotes speculative-grade credit quality. Demand features rated in this category may be supported by a liquidity provider that does not have an investment grade short-term rating or may lack the structural and/or legal protections necessary to ensure the timely payment of purchase price upon demand.

* For VRDBs supported with conditional liquidity support, short-term ratings transition down at higher long-term ratings to reflect the risk of termination of liquidity support as a result of a downgrade below investment grade.

VMIG ratings of VRDBs with unconditional liquidity support reflect the short-term debt rating (or counterparty assessment) of the liquidity support provider with VMIG 1 corresponding to P-1, VMIG 2 to P-2, VMIG 3 to P-3 and SG to not prime.

For more complete discussion of these rating transitions, please see Annex B of Moody's Methodology titled Variable Rate Instruments Supported by Conditional Liquidity Facilities.

US Municipal Short-Term Versus Long-Term Ratings

NOTES	LONG-TERM RATING	DEMAND OBLIGATIONS WITH CONDITIONAL LIQUIDITY SUPPORT
MIG 1	Aaa Aa1 Aa2 Aa3 A1 A2	VMIG 1
MIG 2	A3	VMIG 2
MIG 3	Baa1	VMIG 3*
MIG 3	Baa2 Baa3	SG
SG	Ba1, Ba2, Ba3 B1, B2, B3 Caa1, Caa2, Caa3 Ca, C	SG

* For SBPA-backed VRDBs, The rating transitions are higher to allow for distance to downgrade to below investment grade due to the presence of automatic termination events in the SBPAs.

National Scale Long-Term Ratings

Moody's long-term National Scale Ratings (NSRs) are opinions of the relative creditworthiness of issuers and financial obligations within a particular country. NSRs are not designed to be compared among countries; rather, they address relative credit risk within a given country. Moody's assigns national scale ratings in certain local capital markets in which investors have found the global rating scale provides inadequate differentiation among credits or is inconsistent with a rating scale already in common use in the country.

In each specific country, the last two characters of the rating indicate the country in which the issuer is located (e.g., Aaa.br for Brazil).

Long-Term NSR Scale

Aaa.n	Issuers or issues rated Aaa.n demonstrate the strongest creditworthiness relative to other domestic issuers.
Aa.n	Issuers or issues rated Aa.n demonstrate very strong creditworthiness relative to other domestic issuers.
A.n	Issuers or issues rated A.n present above-average creditworthiness relative to other domestic issuers.
Baa.n	Issuers or issues rated Baa.n represent average creditworthiness relative to other domestic issuers.
Ba.n	Issuers or issues rated Ba.n demonstrate below-average creditworthiness relative to other domestic issuers.
B.n	Issuers or issues rated B.n demonstrate weak creditworthiness relative to other domestic issuers.
Caa.n	Issuers or issues rated Caa.n demonstrate very weak creditworthiness relative to other domestic issuers.
Ca.n	Issuers or issues rated Ca.n demonstrate extremely weak creditworthiness relative to other domestic issuers.
C.n	Issuers or issues rated C.n demonstrate the weakest creditworthiness relative to other domestic issuers.

Note: Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category. National scale long-term ratings of D.ar and E.ar may also be applied to Argentine obligations.

National Scale Short-Term Ratings

Moody's short-term NSRs are opinions of the ability of issuers in a given country, relative to other domestic issuers, to repay debt obligations that have an original maturity not exceeding thirteen months. Short-term NSRs in one country should not be compared with short-term NSRs in another country, or with Moody's global ratings.

There are four categories of short-term national scale ratings, generically denoted N-1 through N-4 as defined below.

In each specific country, the first two letters indicate the country in which the issuer is located (e.g., BR-1 through BR-4 for Brazil).

Short-Term NSR Scale

N-1	Issuers rated N-1 have the strongest ability to repay short-term senior unsecured debt obligations relative to other domestic issuers.
N-2	Issuers rated N-2 have an above average ability to repay short-term senior unsecured debt obligations relative to other domestic issuers.
N-3	Issuers rated N-3 have an average ability to repay short-term senior unsecured debt obligations relative to other domestic issuers.
N-4	Issuers rated N-4 have a below average ability to repay short-term senior unsecured debt obligations relative to other domestic issuers.

Note: The short-term rating symbols P-1.za, P-2.za, P-3.za and NP.za are used in South Africa. National scale short-term ratings of AR-5 and AR-6 may also be applied to Argentine obligations.

Moody's currently maintains long-term and short-term NSRs for the following countries:

- Argentina (.ar)
- Bolivia (.bo)
- Brazil (.br)
- Czech Republic (.cz)
- Kazakhstan (.kz)
- Kenya (.ke)
- Lebanon (.lb)
- Mexico (.mx)
- Morocco (.ma)
- Nigeria (.ng)
- Slovakia (.sk)
- South Africa (.za)
- Tunisia (.tn)
- Turkey (.tr)
- Ukraine (.ua)
- Uruguay (.uy)

Probability of Default Ratings

A probability of default rating (PDR) is a corporate family-level opinion of the relative likelihood that any entity within a corporate family will default on one or more of its long-term debt obligations. For families in default on all of their long-term debt obligations (such as might be the case in bankruptcy), a PDR of D-PD is assigned. For families in default on a limited set of their debt obligations, the PDR is appended by the indicator "/LD", for example, Caa1-PD/LD.

A D-PD probability of default rating is not assigned (or /LD indicator appended) until a failure to pay interest or principal extends beyond any grace period specified by the terms of the debt obligation.

A D-PD probability of default rating is not assigned (or /LD indicator appended) for distressed exchanges until they have been completed, as opposed to simply announced.

Adding or removing the "/LD" indicator to an existing PDR is not a credit rating action.

PDR Scale

Aaa-PD	Corporate families rated Aaa-PD are judged to be of the highest quality, subject to the lowest level of default risk.
Aa-PD	Corporate families rated Aa-PD are judged to be of high quality and are subject to very low default risk.
A-PD	Corporate families rated A-PD are judged to be upper-medium grade and are subject to low default risk.
Baa-PD	Corporate families rated Baa-PD are judged to be medium-grade and subject to moderate default risk and as such may possess certain speculative characteristics.
Ba-PD	Corporate families rated Ba-PD are judged to be speculative and are subject to substantial default risk.
B-PD	Corporate families rated B-PD are considered speculative and are subject to high default risk.
Caa-PD	Corporate families rated Caa-PD are judged to be speculative of poor standing, subject to very high default risk, and may be in default on some but not all of their long-term debt obligations.
Ca-PD	Corporate families rated Ca-PD are highly speculative and are likely in, or very near, default on some but not all of their long-term debt obligations.
C-PD	Corporate families rated C-PD are the lowest rated and are typically in default on some but not all of their long-term debt obligations.
D-PD	Corporate families rated D are in default on all of their long-term debt obligations.

Note: Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa-PD through Caa-PD (e.g., Aa1-PD). The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Other Permissible Services

Assessments of Infonavit's Third Party Collection Agencies

Moody's Assessments of Infonavit's Third Party Collection Agencies are opinions regarding these agencies' ability to collect on Infonavit's mortgage loans. The assessments are provided to independent collection agencies that are contracted by Infonavit to collect on mortgage loans when the loan cannot be serviced via payroll deduction. They are assigned to agencies that service low delinquency pools or/and high delinquency pools. The assessment to these Infonavit service providers applies only in the context of Infonavit's primary servicing operations. As a result, these assessments are not stand-alone servicer/vendor quality ratings and do not refer to the ability of these third party collection agencies to service other types of loans.

Moody's maintains Assessments of Infonavit's Third Party Collection Agencies only in Mexico.

The Instituto del Fondo Nacional de la Vivienda para los Trabajadores (Infonavit) is the Mexican federal institute for workers housing, which originates and securitizes mortgage loans. While initially Infonavit loans are repaid via payroll deduction, once the borrower ceases to work for a company in the private sector the loan is serviced by Infonavit using a network of independent collection agencies.

» Strong
» Above Average
» Average
» Below Average
» Weak

Note: Where appropriate, a "+" or "-" modifier will be appended to the "Above Average", "Average", and "Below Average" category and a "-" modifier will be appended to the "Strong" category. A "+" modifier indicates the agency ranks in the higher end of the designated category. A "-" modifier indicates the agency ranks in the lower end of the designated category.

Bond Fund Ratings

Bond Fund Ratings are opinions of the credit quality of investments within mutual funds and similar investment vehicles which principally invest in medium- and long-term fixed income obligations. As such, these ratings primarily reflect Moody's assessment of the creditworthiness of the assets held by the fund. Other risks, such as liquidity, operational, interest rate, currency and any other market risk, are excluded from the rating. In addition, as the ratings are intended to represent opinions on a fund's underlying assets, they specifically do not consider the historic, current, or prospective performance of a fund with respect to appreciation, volatility of net asset value, or yield.

Bond Fund Rating Scale

Aaa-bf	Bond Funds rated Aaa-bf generally hold assets judged to be of the highest credit quality.
Aa-bf	Bond Funds rated Aa-bf generally hold assets judged to be of high credit quality.
A-bf	Bond Funds rated A-bf generally hold assets considered upper-medium credit quality.
Baa-bf	Bond Funds rated Baa-bf generally hold assets considered medium credit quality.
Ba-bf	Bond Funds rated Ba-bf generally hold assets judged to have speculative elements.
B-bf	Bond Funds rated B-bf generally hold assets considered to be speculative.
Caa-bf	Bond Funds rated Caa-bf generally hold assets judged to be of poor standing.
Ca-bf	Bond Funds rated Ca-bf generally hold assets that are highly speculative and that are likely in, or very near, default, with some prospect of recovery of principal and interest.
C-bf	Bond Funds rated C-bf generally hold assets that are in default, with little prospect for recovery of principal or interest.

Common Representative Quality Assessments

Moody's Common Representative Quality (CRQ) Assessments are opinions regarding an organization's ability to represent the interests of investors, relative to other common representatives within a given country. The assessments represent Moody's assessment of a common representative's organizational structure and other management characteristics, including its human resources allocation, information technology, and operational controls and procedures.

Moody's currently maintains common representative assessments for Mexico.

CRQ Assessment Scale

CRQ1	Strong ability to represent interests of the trust certificate holders.
CRQ2	Above-average ability to represent interests of the trust certificate holders. Common representative is judged to have "good" financial and operational stability.
CRQ3	Average ability to represent interests of the trust certificate holders. Common representative is judged to have average financial and operational stability.
CRQ4	Below-average ability to represent interests of the trust certificate holders, and below average financial and operational stability.
CRQ5	Weak ability to represent interests of the trust certificate holders, and weak financial and operational stability.

Note: Where appropriate, a "+" or "-" modifier will be appended to the CRQ2, CRQ3, and CRQ4 assessment categories, a "-" modifier will be appended to the CRQ1 rating category and a "+" modifier will be appended to the CRQ5 rating category. A "+" modifier indicates the common representative ranks in the higher end of the designated assessment category. A "-" modifier indicates the common representative ranks in the lower end of the designated assessment category.

Contract Enforceability Indicators for Mexican States

Contract enforceability indicators are opinions of the relative effectiveness of Mexican states in enforcing disputed commercial contracts and mortgages. The indicators provide an ordinal ranking and do not address the absolute effectiveness of state judicial systems. Contract enforceability indicators are assigned to individual states based on a standardized weighting of results generated by independent, questionnaire-based, studies conducted by the Instituto Tecnológico Autonomy de México (ITAM), a Mexican university, and Gaxiola Calvo Sobrino y Asociados (GCSA), a Mexican law firm. As the indicators are derived primarily from public opinion polls, which may vary due to changes in participants and/or perceptions, they are not directly comparable from one study to another. Accordingly, the indicators are point-in-time assessments and are not monitored between studies.

Contract Enforceability Scale

EC1	Highest effectiveness in handling commercial cases and enforcing resolutions in Mexico.
EC2	Above average effectiveness in handling commercial cases and enforcing resolutions in Mexico.
EC3	Average effectiveness in handling commercial cases and enforcing resolutions in Mexico.
EC4	Below average effectiveness in handling commercial cases and enforcing resolutions in Mexico.
EC5	Weakest effectiveness in handling commercial cases and enforcing resolutions in Mexico.

Credit Estimates

A Credit Estimate (CE) is an unpublished point-in-time opinion of the approximate credit quality of individual securities, financial contracts, issuers, corporate families or loans. CEs are not Moody's Credit Ratings and are not assigned by rating committees. Had Moody's conducted an analysis commensurate with a full Moody's Credit Rating, the result may have been significantly different. Additionally, CEs are not monitored but are often updated from time to time.

CEs are widely used in the process of assessing elements of credit risk in transactions for which a traditional Moody's Credit Rating is to be determined. CEs are provided in the context of granular pools (where no one obligor represents an exposure of more than 3% of the total pool), chunky pools (where individual exposures represent 3% or more of the total pool) or single-name exposures.

CEs are typically assigned based on an analysis that uses public information (which at times may be limited) or information supplied by various third parties and usually does not involve any participation from the underlying obligor.

CEs are not expressed through the use of Moody's traditional 21-point, Aaa-C alphanumeric long-term rating scale; rather, they are expressed on a simple numerical 1-21 scale. They are calibrated, however, to be broadly comparable to Moody's alphanumeric rating scale and Moody's Rating Factors, which are used in CDO analysis.

Equity Fund Assessments

Moody's equity fund assessments are opinions of the relative investment quality of investment funds, which principally invest in common stock or in a combination of common stock and fixed-income securities. Investment quality is judged based on the fund's historical performance relative to funds employing a similar investment strategy, as well as on the quality of the fund manager.

The assessments are not opinions on prospective performance of a fund with respect to asset appreciation, volatility of net asset value or yield.

Equity Fund Assessment Scale

EF-1	Equity funds assessed at EF-1 have the highest investment quality relative to funds with a similar investment strategy
EF-2	Equity funds assessed at EF-2 have high investment quality relative to funds with a similar investment strategy
EF-3	Equity funds assessed at EF-3 have moderate investment quality relative to funds with a similar investment strategy
EF-4	Equity funds assessed at EF-4 have low investment quality relative to funds with a similar investment strategy
EF-5	Equity funds assessed at EF-5 have the lowest investment quality relative to funds with a similar investment strategy

Green Bonds Assessments (GBAs)

Green Bonds Assessments are forward-looking opinions on the relative effectiveness of the approaches adopted by green bond issuers to manage, administer, allocate proceeds to and report on environmental projects financed with proceeds derived from green bond offerings. GBAs are assigned to individual green bonds.

Green Bond Assessment Scale

GB1	Green bond issuer has adopted an excellent approach to manage, administer, allocate proceeds to and report on environmental projects financed with proceeds derived from green bond offerings. Prospects for achieving stated environmental objectives are excellent.
GB2	Green bond issuer has adopted a very good approach to manage, administer, allocate proceeds to and report on environmental projects financed with proceeds derived from green bond offerings. Prospects for achieving stated environmental objectives are very good.
GB3	Green bond issuer has adopted a good approach to manage, administer, allocate proceeds to and report on environmental projects financed with proceeds derived from green bond offerings. Prospects for achieving stated environmental objectives are good.
GB4	Green bond issuer has adopted a fair approach to manage, administer, allocate proceeds to and report on environmental projects financed with proceeds derived from green bond offerings. Prospects for achieving stated environmental objectives are fair.
GB5	Green bond issuer has adopted a poor approach to manage, administer, allocate proceeds to and report on environmental projects financed with proceeds derived from green bond offerings. Prospects for achieving stated environmental objectives are poor.

Indicative Ratings

An Indicative Rating is a confidential, unpublished, unmonitored, point-in-time opinion of the potential Credit Rating(s) of an issuer or a proposed debt issuance by an issuer contemplating such a debt issuance at some future date. Indicative Ratings are not equivalent to and do not represent traditional MIS Credit Ratings. However, Indicative Ratings are expressed on MIS's traditional rating scale.

Investment Manager Quality Assessments

Moody's Investment Manager Quality assessments are forward-looking opinions of the relative investment expertise and service quality of asset managers. An MQ assessment provides an additional tool for investors to aid in their investment decision-making process. Moody's MQ assessments provide general insights into the quality of an asset manager, including how it manages its investment offerings and serves its clientele.

MQ assessments do not indicate an asset manager's ability to repay a fixed financial obligation or satisfy contractual financial obligations, neither those entered by the firm nor any that may have been entered into through actively managed portfolios.

The assessments are also not intended to evaluate the performance of a portfolio, mutual fund, or other investment vehicle with respect to appreciation, volatility of net asset value, or yield. Instead, MQ assessments are opinions about the quality of an asset manager's management and client service characteristics as expressed through the symbols below.

Investment Manager Quality assessment definitions are as follows:

Manager Quality Assessment Scale

MQ1	Investment managers assessed at MQ1 exhibit excellent management characteristics.
MQ2	Investment managers assessed at MQ2 exhibit very good management characteristics.
MQ3	Investment managers assessed at MQ3 exhibit good management characteristics.
MQ4	Investment managers assessed at MQ4 exhibit adequate management characteristics.
MQ5	Investment managers assessed at MQ5 exhibit poor management characteristics.

Market Risk Assessments

Moody's Market Risk Assessments (MRAs) are opinions of the relative degree of historical volatility of a rated fund's NAV. MRAs are not intended to consider prospective performance of funds with respect to price appreciation or yield.

Market Risk Assessment Scale

MRA1	Funds rated MRA1 have had **very low sensitivity** to changes in interest rates and other market conditions
MRA2	Funds rated MRA2 have had **low sensitivity** to changes in interest rates and other market conditions
MRA3	Funds rated MRA3 have had **between low and moderate sensitivity** to changes in interest rates and other market conditions
MRA4	Funds rated MRA4 have had **moderate sensitivity** to changes in interest rates and other market conditions
MRA5	Funds rated MRA5 have had **between moderate and high sensitivity** to changes in interest rates and other market conditions
MRA6	Funds rated MRA6 have had **high sensitivity** to changes in interest rates and other market conditions
MRA7	Funds rated MRA7 have had **very high sensitivity** to changes in interest rates and other market conditions

Note: MRAs are assigned only in Mexico.

Money Market Fund (mf) Ratings

Moody's Money Market Fund Ratings are opinions of the investment quality of shares in mutual funds and similar investment vehicles which principally invest in short-term fixed income obligations. As such, these ratings incorporate Moody's assessment of a fund's published investment objectives and policies, the creditworthiness of the assets held by the fund, the liquidity profile of the fund's assets relative to the fund's investor base, the assets' susceptibility to market risk, as well as the management characteristics of the fund. The ratings are not intended to consider the prospective performance of a fund with respect to appreciation, volatility of net asset value, or yield.

Money Market Fund Rating Scale

Aaa-mf	Money market funds rated Aaa-mf have very strong ability to meet the dual objectives of providing liquidity and preserving capital.
Aa-mf	Money market funds rated Aa-mf have strong ability to meet the dual objectives of providing liquidity and preserving capital.
A-mf	Money market funds rated A-mf have moderate ability to meet the dual objectives of providing liquidity and preserving capital.
Baa-mf	Money market funds rated Baa-mf have marginal ability to meet the dual objectives of providing liquidity and preserving capital.
B-mf	Money market funds rated B-mf are unable to meet the objective of providing liquidity and have marginal ability to meet the objective of preserving capital.
C-mf	Money market funds rated C-mf are unable to meet either objective of providing liquidity or preserving capital.

National Scale Stock Ratings

National Scale Stock ("NSSR") ratings provide an ordinal ranking of a company's ability to pay and sustain common stock dividend payments while also providing an assessment of the stock's trading liquidity in its principal market. Moody's currently issues NSSRs for stocks traded on the Argentinean, Bolivian, Colombian, and Uruguayan stock markets. NSSRs are expressed on a 1 through 4 rating scale.

NSSR Scale

1	Issuers that exhibit a very strong combination of liquidity and dividend sustainability.
2	Issuers that exhibit a strong combination of liquidity and dividend sustainability.
3	Issuers that exhibit a fair combination of liquidity and dividend sustainability.
4	Issuers that exhibit a poor combination of liquidity and dividend sustainability.

Originator Assessments

Moody's Originator Assessments (OAs) are Moody's opinions on the strength and stability of originators' policies and practices as they affect defaults and losses in structured finance securities backed by loans, relative to other originators of the same type of loans within a given country. OAs consider early/mid-stage loan performance, originator ability and originator stability. Originator assessments look to isolate the effects an originator's policies and practices have on loan performance from the effects of external factors such as the macroeconomic environment and the ability of the servicer.

Moody's assigns originators one of the following five assessment levels: Strong, Above Average, Average, Below Average, Weak.

Q-scores

Q-scores are assessments that are scorecard generated, unpublished, point-in-time estimates of the approximate credit quality of individual sub-sovereign entities (regional & local governments and government related issuers). They provide a granular assessment of individual credit exposures within large pool transactions. Q-scores are not equivalent to and do not represent traditional Moody's Credit Ratings and are not assigned by a rating committee. Q-scores, in large numbers, assist in the analysis of mean portfolio credit risk and provide the distribution of credit risk of a large pool from the underlying exposures.

Q-scores are not expressed through the use of Moody's traditional 21-point, Aaa-C alphanumeric long-term rating scale; rather, they are expressed on a simple numerical 1.q-21.q scale.

Rating Assessment Services

The Rating Assessment Service or RAS is a confidential, unpublished, unmonitored, point-in-time opinion of the potential Credit Rating(s), or the potential impact on the current Credit Rating(s), given one or more hypothetical Scenario(s) (defined below) communicated to MIS in writing by a Rated Entity or other applicant. Rating Assessments are not equivalent to and do not represent traditional MIS Credit Ratings. However, Rating Assessments are expressed on MIS's traditional rating scale.

A Scenario is a proposed credit transforming transaction, project and/or debt issuance which materially alters the issuer's current state (including acquisitions, disposals, share buybacks, listings, initial public offerings and material restructurings), or a materially different variation on such a transaction, project and/or debt issuance, including a material change in the overall size of the debt being contemplated.

Servicer Quality Assessments

Moody's Servicer Quality (SQ) assessments are opinions on the strength and stability of servicers' policies and practices in preventing defaults and maximizing recoveries for the receivables they service, relative to other servicers performing the same servicing role within a given country.

SQ assessments are provided for servicers who act as the Primary Servicer (servicing the assets from beginning to end), Special Servicer (servicing only the more delinquent assets), or Master Servicer (overseeing the performance and reporting from underlying servicers). Each SQ assessment is assigned for a specific servicing role by reference to the servicing activity and product type.

SQ assessments represent Moody's assessment of a servicer's ability to affect losses based on factors under the servicer's control. The SQ approach works by separating a servicer's performance from the credit quality of the assets being serviced. In doing this, Moody's evaluates how effective a servicer is at preventing defaults and maximizing recoveries to a transaction when defaults occur.

SQ assessments consider the operational and financial stability of a servicer as well as its ability to respond to changing market conditions. This assessment is based on the company's organizational structure, management characteristics, financial profile, operational controls and procedures as well as its strategic goals.

Moody's SQ assessments are different from traditional debt ratings, which are opinions as to the credit quality of a specific instrument. SQ assessments do not apply to a company's ability to repay a fixed financial obligation or satisfy contractual financial obligations other than, in limited circumstances, the obligation to advance on delinquent assets it services, when such amounts are believed to be recoverable.

Servicer Quality Assessment Scale

SQ1	Strong combined servicing ability and servicing stability
SQ2	Above average combined servicing ability and servicing stability
SQ3	Average combined servicing ability and servicing stability
SQ4	Below average combined servicing ability and servicing stability
SQ5	Weak combined servicing ability and servicing stability

Note: Where appropriate, a "+" or "-" modifier will be appended to the SQ2, SQ3, and SQ4 rating categories, a "-" modifier will be appended to the SQ1 rating category and a "+" modifier will be appended to the SQ5 rating category. A "+" modifier indicates the servicer ranks in the higher end of the designated rating category. A "-" modifier indicates the servicer ranks in the lower end of the designated rating category.

Trustee Quality Assessments

Moody's Trustee Quality (TQ) Assessments are opinions regarding an organization's ability to manage the entrusted assets for the benefit of investors, relative to other trustees within a given country. The assessments represent Moody's assessment of a trustee's organizational structure and other management characteristics, including its monitoring and reporting system, human resources allocation, information technology, operational controls and procedures, and master servicing capability.

Moody's currently maintains trustee quality assessments for the following countries:

» Argentina
» Brazil
» Mexico

Trustee Quality Assessment Scale

TQ1	Strong capability of managing entrusted assets for the benefit of the trust certificate holders.
TQ2	Above-average capability of managing entrusted assets for the benefit of the trust certificate holders. Trustee is judged to have "good" financial and operational stability.
TQ3	Average capability of managing entrusted assets for the benefit of the trust certificate holders. Trustee is judged to have average financial and operational stability.
TQ4	Below-average capability of managing entrusted assets for the benefit of the trust certificate holders, and below-average financial and operational stability.
TQ5	Weak capability of managing entrusted assets for the benefit of the trust certificate holders, and weak financial and operational stability.

Note: Where appropriate, a "+" or "-" modifier will be appended to the TQ2, TQ3, and TQ4 assessment categories, a "-" modifier will be appended to the TQ1 rating category and a "+" modifier will be appended to the TQ5 rating category. A "+" modifier indicates the trustee ranks in the higher end of the designated rating category. A "-" modifier indicates the trustee ranks in the lower end of the designated assessment category..

Other Rating Symbols

Expected ratings - e

To address market demand for timely information on particular types of credit ratings, Moody's has licensed to certain third parties the right to generate "Expected Ratings." Expected Ratings are designated by an "e" after the rating code, and are intended to anticipate Moody's forthcoming rating assignments based on reliable information from third party sources (such as the issuer or underwriter associated with the particular securities) or established Moody's rating practices (i.e., medium term notes are typically, but not always, assigned the same rating as the note's program rating). Expected Ratings will exist only until Moody's confirms the Expected Rating, or issues a different rating for the relevant instrument. Moody's encourages market participants to contact Moody's Ratings Desk or visit www.moodys.com if they have questions regarding Expected Ratings, or wish Moody's to confirm an Expected Rating.

Provisional Ratings - (P)

Moody's will often assign a provisional rating to program ratings or to an issuer or an instrument when the assignment of a definitive rating is subject to the fulfilment of contingencies that are highly likely to be completed. Upon fulfillment of these contingencies, such as finalization of documents and issuance of the securities, the provisional notation is removed.[6] A provisional rating is denoted by placing a (P) in front of the rating.[7]

Refundeds -

Issues that are secured by escrowed funds held in trust, reinvested in direct, non-callable US government obligations or non-callable obligations unconditionally guaranteed by the US Government or Resolution Funding Corporation are identified with a # (hatch mark) symbol, e.g., #Aaa.

Withdrawn - WR

When Moody's no longer rates an obligation on which it previously maintained a rating, the symbol WR is employed. Please see Moody's Guidelines for the Withdrawal of Ratings, available on www.moodys.com.

Not Rated - NR

NR is assigned to an unrated issuer, obligation and/or program.

Not Available - NAV

An issue that Moody's has not yet rated is denoted by the NAV symbol.

Terminated Without Rating - TWR

The symbol TWR applies primarily to issues that mature or are redeemed without having been rated.

6 Program ratings for shelf registrations and medium term notes remain provisional while any ratings assigned to issues under these programs are definitive ratings. Provisional ratings may also be assigned to unexecuted credit default swap contracts or other debt-like obligations that define specific credit risk exposures facing individual financial institutions. In such cases, the drafter of the swap or other debt-like obligation may have no intention of executing the agreement, and, therefore, the provisional notation is unlikely to ever be removed.

7 Provisional ratings may not be assigned by Moody's de Mexico.

Inputs to Rating Services

Inputs to Rating Services are not Credit Ratings and they are expressed using differentiated symbols to distinguish them from Credit Ratings. Their use in helping to assign Credit Ratings is described in the respective Credit Rating Methodologies where they are used.

Baseline Credit Assessments

Baseline credit assessments (BCAs) are opinions of issuers' standalone intrinsic strength, absent any extraordinary support from an affiliate[8] or a government. BCAs are essentially an opinion on the likelihood of an issuer requiring extraordinary support to avoid a default on one or more of its debt obligations or actually defaulting on one or more of its debt obligations in the absence of such extraordinary support.

As probability measures, BCAs do not provide an opinion on the severity of a default that would occur in the absence of extraordinary support.

Contractual relationships and any expected ongoing annual subsidies from the government or an affiliate are incorporated in BCAs and, therefore, are considered intrinsic to an issuer's standalone financial strength. Extraordinary support is typically idiosyncratic in nature and is extended to prevent an issuer from becoming nonviable.

BCAs are expressed on a lower-case alpha-numeric scale that corresponds to the alpha-numeric ratings of the global long-term rating scale.

BCA Scale

aaa	Issuers assessed **aaa** are judged to have the highest intrinsic, or standalone, financial strength, and thus subject to the lowest level of credit risk absent any possibility of extraordinary support from an affiliate or a government.
aa	Issuers assessed **aa** are judged to have high intrinsic, or standalone, financial strength, and thus subject to very low credit risk absent any possibility of extraordinary support from an affiliate or a government.
a	Issuers assessed **a** are judged to have upper-medium-grade intrinsic, or standalone, financial strength, and thus subject to low credit risk absent any possibility of extraordinary support from an affiliate or a government.
baa	Issuers assessed **baa** are judged to have medium-grade intrinsic, or standalone, financial strength, and thus subject to moderate credit risk and, as such, may possess certain speculative credit elements absent any possibility of extraordinary support from an affiliate or a government.
ba	Issuers assessed **ba** are judged to have speculative intrinsic, or standalone, financial strength, and are subject to substantial credit risk absent any possibility of extraordinary support from an affiliate or a government.
b	Issuers assessed **b** are judged to have speculative intrinsic, or standalone, financial strength, and are subject to high credit risk absent any possibility of extraordinary support from an affiliate or a government.
caa	Issuers assessed **caa** are judged to have speculative intrinsic, or standalone, financial strength, and are subject to very high credit risk absent any possibility of extraordinary support from an affiliate or a government.
ca	Issuers assessed **ca** have highly speculative intrinsic, or standalone, financial strength, and are likely to be either in, or very near, default, with some prospect for recovery of principal and interest; or, these issuers have avoided default or are expected to avoid default through the provision of extraordinary support from an affiliate or a government.
c	Issuers assessed **c** are typically in default, with little prospect for recovery of principal or interest; or, these issuers are benefiting from a government or affiliate support but are likely to be liquidated over time; without support there would be little prospect for recovery of principal or interest.

Note: Moody's appends numerical modifiers 1, 2, and 3 to each generic assessment classification from aa through caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic assessment category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic assessment category.

8 Affiliate includes a parent, cooperative groups and significant investors (typically with a greater than 20 percent voting interest). Government includes local, regional and national governments.

Counterparty Risk Assessments

Counterparty risk assessments (CR assessments) are opinions on the likelihood of a default by an issuer on certain senior operating obligations and other contractual commitments. CR assessments are assigned to legal entities in banking groups and, in some instances, other regulated institutions with similar bank-like senior obligations. CR assessments address the likelihood of default and do not take into consideration the expected severity of loss in the event of default.

Obligations and commitments typically covered by CR assessments include payment obligations associated with covered bonds (and certain other secured transactions), derivatives, letters of credit, third party guarantees, servicing and trustee obligations and other similar operational obligations that arise from a bank in performing its essential client-facing operating functions.

Long-term CR assessments reference obligations with an original maturity of one year or more. Short-term CR assessments reference obligations with an original maturity of thirteen months or less. CR assessments are expressed on alpha-numeric scales that correspond to the alpha-numeric ratings of the global long-term and short-term rating scales, with a "(cr)" modifier appended to the CR assessment symbols to differentiate them from our credit ratings.

CR Assessment Long-Term Scale

Aaa(cr)	Issuers assessed Aaa(cr) are judged to be of the highest quality, subject to the lowest level of risk of defaulting on certain senior operating obligations and other contractual commitments.
Aa(cr)	Issuers assessed Aa(cr) are judged to be of high quality and are subject to very low risk of defaulting on certain senior operating obligations and other contractual commitments.
A(cr)	Issuers assessed A(cr) are judged to be upper-medium grade and are subject to low risk of defaulting on certain senior operating obligations and other contractual commitments.
Baa(cr)	Issuers assessed Baa(cr) are judged to be medium-grade and subject to moderate risk of defaulting on certain senior operating obligations and other contractual commitments and as such may possess certain speculative characteristics.
Ba(cr)	Issuers assessed Ba(cr) are judged to be speculative and are subject to substantial risk of defaulting on certain senior operating obligations and other contractual commitments.
B(cr)	Issuers assessed B(cr) are considered speculative and are subject to high risk of defaulting on certain senior operating obligations and other contractual commitments.
Caa(cr)	Issuers assessed Caa(cr) are judged to be speculative of poor standing and are subject to very high risk of defaulting on certain senior operating obligations and other contractual commitments.
Ca(cr)	Issuers assessed Ca(cr) are highly speculative and are likely in, or very near, default on certain senior operating obligations and other contractual commitments.
C(cr)	Issuers assessed C(cr) are the lowest rated and are typically in default on certain senior operating obligations and other contractual commitments.

Note: Moody's appends numerical modifiers 1, 2, and 3 to each generic assessment classification from Aa(cr) through Caa(cr). The modifier 1 indicates that the issuer ranks in the higher end of its generic assessment category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic assessment category.

CR Assessment Short-Term Scale

P-1(cr)	Issuers assessed Prime-1(cr) have a superior ability to honor short-term operating obligations..
P-2(cr)	Issuers assessed Prime-2(cr) have a strong ability to honor short-term operating obligations.
P-3(cr)	Issuers assessed Prime-3(cr) have an acceptable ability to honor short-term operating obligations.
NP(cr)	Issuers assessed Not Prime(cr) do not fall within any of the Prime rating categories.

Loss Given Default Assessments

Moody's Loss Given Default (LGD) assessments are opinions about expected loss given default expressed as a percent of principal and accrued interest at the resolution of the default.[9] LGD assessments are assigned to individual loan, bond, and preferred stock issues. The firm-wide or enterprise expected LGD rate generally approximates a weighted average of the expected LGD rates on the firm's liabilities (excluding preferred stock), where the weights equal each obligation's expected share of the total liabilities at default.

LGD Assessment Scale

Assessments	Loss range
LGD1	≥ 0% and < 10%
LGD2	≥ 10% and < 30%
LGD3	≥ 30% and < 50%
LGD4	≥ 50% and < 70%
LGD5	≥ 70% and < 90%
LGD6	≥ 90% and ≤ 100%

9 The expected LGD rate is 100% minus the expected value that will be received at default resolution, discounted by the coupon rate back to the date the last debt service payment was made, and divided by the principal outstanding at the date of the last debt service payment.

Structured Credit Assessments (SCAs)

Structured Credit Assessments (SCAs) are opinions of the relative credit quality of financial obligations that are collateral assets within securitizations. SCAs incorporate the credit implications of structural features of the securitization that are not intrinsic to the obligation, such as servicing, liquidity arrangements and tail periods.[10] In contrast, credit ratings on these same instruments do not reflect these structural features, as they would not be available to investors that invest in these assets directly outside of the securitization's structure.

Structured Credit Assessments are opinions of the expected loss associated with the financial obligation in the context of the corresponding securitization transaction and are expressed, with the sca indicator, on a lower-case alpha-numeric scale that corresponds to the alpha-numeric ratings of the global long-term rating scale.

SCA Scale

aaa (sca)	Financial obligations assessed aaa (sca) are judged to have the highest credit quality and thus subject to the lowest credit risk, when used as inputs in determining a structured finance transaction's rating.
aa (sca)	Financial obligations assessed aa (sca) are judged to have high credit quality and thus subject to very low credit risk, when used as inputs in determining a structured finance transaction's rating.
a (sca)	Financial obligations assessed a (sca) are judged to have upper-medium credit quality and thus subject to low credit risk, when used as inputs in determining a structured finance transaction's rating.
baa (sca)	Financial obligations assessed baa (sca) are judged to have medium-grade credit quality and thus subject to moderate credit risk, and as such, may possess certain speculative credit elements, when used as inputs in determining a structured finance transaction's rating.
ba (sca)	Financial obligations assessed ba (sca) are judged to have speculative credit quality and subject to substantial credit risk, when used as inputs in determining a structured finance transaction's rating.
b (sca)	Financial obligations assessed b (sca) are judged to have speculative credit quality and subject to high credit risk, when used as inputs in determining a structured finance transaction's rating.
caa (sca)	Financial obligations assessed caa (sca) are judged to have speculative credit quality and subject to very high credit risk, when used as inputs in determining a structured finance transaction's rating.
ca (sca)	Financial obligations assessed ca (sca) are judged to be highly speculative and are likely to be either in, or very near, default, with some prospect for recovery of principal or interest, when used as inputs in determining a structured finance transaction's rating.
c (sca)	Financial obligations assessed c (sca) are typically in default with little prospect for recovery of principal or interest, when used as inputs in determining a structured finance transaction's rating.

Notes:

1. Moody's appends numerical modifiers 1, 2, and 3 to each generic assessment classification from aa (sca) through caa (sca). The modifier 1 indicates that the obligation ranks in the higher end of its generic assessment category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic assessment category.
2. The modifier pd indicates a probability of default structured credit assessment (for example aaa (sca.pd)). A probability of default structured credit assessment is an opinion of the relative likelihood that the financial instrument will default.

10 Structural features of securitisations often include: servicing of the loans by third party experts, liquidity arrangements to mitigate specific risks or the risk of short term cash flow interruptions, and tail periods between the loan maturity date and the loss calculation date to allow for an orderly sale of the assets upon default.

Other Definitions

Rating Outlooks

A Moody's rating outlook is an opinion regarding the likely rating direction over the medium term. Rating outlooks fall into four categories: Positive (POS), Negative (NEG), Stable (STA), and Developing (DEV). Outlooks may be assigned at the issuer level or at the rating level. Where there is an outlook at the issuer level and the issuer has multiple ratings with differing outlooks, an "(m)" modifier to indicate multiple will be displayed and Moody's written research will describe and provide the rationale for these differences. A designation of RUR (Rating(s) Under Review) indicates that an issuer has one or more ratings under review, which overrides the outlook designation. A designation of RWR (Rating(s) Withdrawn) indicates that an issuer has no active ratings to which an outlook is applicable. Rating outlooks are not assigned to all rated entities. In some cases, this will be indicated by the display NOO (No Outlook).

A stable outlook indicates a low likelihood of a rating change over the medium term. A negative, positive or developing outlook indicates a higher likelihood of a rating change over the medium term. A rating committee that assigns an outlook of stable, negative, positive, or developing to an issuer's rating is also indicating its belief that the issuer's credit profile is consistent with the relevant rating level at that point in time.

The time between the assignment of a new rating outlook and a subsequent rating action has historically varied widely, depending upon the pace of new credit developments which materially affect the issuer's credit profile. On average, after the initial assignment of a positive or negative rating outlook, the next rating action – either a change in outlook, a rating review, or a change in rating – has followed within about a year, but outlooks have also remained in place for much shorter and much longer periods of time. Historically, approximately one-third of issuers have been downgraded (upgraded) within 18 months of the assignment of a negative (positive) rating outlook. After the initial assignment of a stable outlook, about 90% of ratings experience no change in rating during the following year.

Rating Reviews

A review indicates that a rating is under consideration for a change in the near term.[11] A rating can be placed on review for upgrade (UPG), downgrade (DNG), or more rarely with direction uncertain (UNC). A review may end with a rating being upgraded, downgraded, or confirmed without a change to the rating. Ratings on review are said to be on Moody's "Watchlist" or "On Watch". Ratings are placed on review when a rating action may be warranted in the near term but further information or analysis is needed to reach a decision on the need for a rating change or the magnitude of the potential change.

The time between the origination of a rating review and its conclusion varies widely depending on the reason for the review and the amount of time needed to obtain and analyze the information relevant to make a rating determination. In some cases, the ability to conclude a review is dependent on whether a specific event occurs, such as the completion of a corporate merger or the execution of an amendment to a structured finance security. In these event-dependent cases and other unique situations, reviews can sometimes last 90 to 180 days or even longer. For the majority of reviews, however, where the conclusion of the review is not dependent on an event whose timing Moody's cannot control, reviews are typically concluded within 30 to 90 days.

Ratings on review for possible downgrade (upgrade) have historically concluded with a downgrade (upgrade) over half of the time.

Confirmation of a Rating

A Confirmation is a public statement that a previously announced review of a rating has been completed without a change to the rating.

11 Baseline Credit Assessments and Counterparty Risk Assessments may also be placed on review.

Affirmation of a Rating

An Affirmation is a public statement that the current Credit Rating assigned to an issuer or debt obligation, which is not currently under review, continues to be appropriately positioned. An Affirmation is generally issued to communicate Moody's opinion that a publicly visible credit development does not have a direct impact on an outstanding rating.

Anticipated/Subsequent Ratings Process

The process of assigning Credit Ratings that are derived exclusively from an existing Credit Rating of a program, series, category/class of debt or primary Rated Entity. This includes:

- An assignment of a Credit Rating to a new issuance, take-down or take-down-like debt within or under an existing rated program, without impact on the program's Credit Rating (including frequent issues from a "shelf registration");
- Credit Ratings based on the pass-through of a primary Rated Entity's Credit Rating, including monoline or guarantee linked ratings;
- An assignment of Credit Ratings to securities of the same seniority as previously rated debt when existing Credit Ratings had already contemplated issuance of that debt (including Credit Ratings released from Federal Agency Queue issued by federal agencies or other specialty common queues). This also includes Credit Ratings assigned to new debts or amended and extended credit facilities which replace similarly structured debts or credit facilities at the same rating level;
- An assignment of a definitive Credit Rating to replace a previously assigned provisional rating (i.e., (P) rating) at the same rating level, or a definitive rating assigned to a security being issued from a program carrying a provisional rating, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive Credit Rating in a manner that would have affected the Credit Rating.

Rating Agency Conditions (RACs)

Parties to a transaction sometimes choose to include clauses in the transaction documents that require a party thereto to obtain an opinion from a rating agency that certain specified actions, events, changes to the structure of, or amendments to the documentation of, the transaction will not result in a reduction or withdrawal of the current rating maintained by that rating agency. Such an opinion is referred to by Moody's as a "RAC" and consists of a letter or other written communication, such as a press release, from Moody's issued after consideration of a request that Moody's provide a RAC. The decision to issue a RAC remains entirely within Moody's discretion, and Moody's may choose not to provide a RAC even if the transaction documents require it. When Moody's chooses to issue a RAC, the RAC reflects Moody's opinion solely that the specified action, event, change in structure or amendment, in and of itself and as of that point in time, will not result in a reduction or withdrawal of Moody's current rating on the debt. A RAC is not a "confirmation" or "affirmation" of the rating, as those terms are defined elsewhere in this Rating Symbols and Definitions publication, nor should it be interpreted as Moody's "approval of" or "consent to" the RAC subject matter.

Covenant Quality Assessments

Moody's covenant quality assessments measure the investor protections provided by key bond covenants within an indenture. The assessments are unmonitored, point-in-time scores, but may be updated as circumstances dictate. Key covenants assessed include provisions for restricted payments, change of control, limitations on debt incurrence, negative pledges, and merger restrictions, among others.

Speculative Grade Liquidity Ratings

Moody's Speculative Grade Liquidity Ratings are opinions of an issuer's relative ability to generate cash from internal resources and the availability of external sources of committed financing, in relation to its cash obligations over the coming 12 months. Speculative Grade Liquidity Ratings will consider the likelihood that committed sources of financing will remain available. Other forms of liquidity support will be evaluated and consideration will be given to the likelihood that these sources will be available during the coming 12 months. Speculative Grade Liquidity Ratings are assigned to speculative grade issuers that are by definition Not Prime issuers.

SGL Rating Scale

SGL-1	Issuers rated SGL-1 possess very good liquidity. They are most likely to have the capacity to meet their obligations over the coming 12 months through internal resources without relying on external sources of committed financing.
SGL-2	Issuers rated SGL-2 possess good liquidity. They are likely to meet their obligations over the coming 12 months through internal resources but may rely on external sources of committed financing. The issuer's ability to access committed sources of financing is highly likely based on Moody's evaluation of near-term covenant compliance.
SGL-3	Issuers rated SGL-3 possess adequate liquidity. They are expected to rely on external sources of committed financing. Based on its evaluation of near-term covenant compliance, Moody's believes there is only a modest cushion, and the issuer may require covenant relief in order to maintain orderly access to funding lines.
SGL-4	Issuers rated SGL-4 possess weak liquidity. They rely on external sources of financing and the availability of that financing is, in Moody's opinion, highly uncertain.

Definition of Default

Moody's definition of default is applicable only to debt or debt-like obligations (e.g., swap agreements). Four events constitute a debt default under Moody's definition:

a. a missed or delayed disbursement of a contractually-obligated interest or principal payment (excluding missed payments cured within a contractually allowed grace period), as defined in credit agreements and indentures;

b. a bankruptcy filing or legal receivership by the debt issuer or obligor that will likely cause a miss or delay in future contractually-obligated debt service payments;

c. a distressed exchange whereby 1) an issuer offers creditors a new or restructured debt, or a new package of securities, cash or assets, that amount to a diminished value relative to the debt obligation's original promise and 2) the exchange has the effect of allowing the issuer to avoid a likely eventual default;

d. a change in the payment terms of a credit agreement or indenture imposed by the sovereign that results in a diminished financial obligation, such as a forced currency re-denomination (imposed by the debtor, or the debtor's sovereign) or a forced change in some other aspect of the original promise, such as indexation or maturity.[12]

We include distressed exchanges in our definition of default in order to capture credit events whereby issuers effectively fail to meet their debt service obligations but do not actually file for bankruptcy or miss an interest or principal payment. Moody's employs fundamental analysis in assessing the likelihood of future default and considers various indicators in assessing loss relative to the original promise, which may include the yield to maturity of the debt being exchanged.

Moody's definition of default does not include so-called "technical defaults," such as maximum leverage or minimum debt coverage violations, unless the obligor fails to cure the violation and fails to honor the resulting debt acceleration which may be required. For structured finance securities, technical defaults (such as breach of an overcollateralization test or certain other events of default as per the legal documentation of the issuer), or a temporary missed interest payment on a security whose terms allow for the deferral of such payments together with corresponding interest (such as PIKable securities) prior to its legal final maturity date do not constitute defaults.

12 Moreover, unlike a general tax on financial wealth, the imposition of a tax by a sovereign on the coupon or principal payment on a specific class of government debt instruments (even if retroactive) would represent a default. Targeted taxation on government securities would represent a default even if the government's action were motivated by fairness or other considerations, rather than inability or unwillingness to pay.

Also excluded are payments owed on long-term debt obligations which are missed due to purely technical or administrative errors which are 1) not related to the ability or willingness to make the payments and 2) are cured in very short order (typically, 1-2 business days). Finally, in select instances based on the facts and circumstances, missed payments on financial contracts or claims may be excluded if they are the result of legal disputes regarding the validity of those claims.

Definition of Impairment

A security is impaired when investors receive — or expect to receive with near certainty — less value than would be expected if the obligor were not experiencing financial distress or otherwise prevented from making payments by a third party, even if the indenture or contractual agreement does not provide the investor with a natural remedy for such events, such as the right to press for bankruptcy.

Moody's definition of impairment is applicable to debt, preferred stock, and other hybrid securities. A security is deemed to be impaired if:

a. all events that meet the definition of default (above);
b. contractually-allowable payment omissions of scheduled dividends, interest or principal payments on debt, preferred stock or other hybrid instruments[13] or contractually allowable interruptions of interest payments to similar structured finance instruments[14];
c. downgrades to Ca or C, signalling the near certain expectation of a significant level of future losses;
d. write-downs or "impairment distressed exchanges"[15] on debt, preferred stock or other hybrid instruments due to financial distress whereby (1) the principal promise to an investor is reduced according to the terms of the indenture or other governing agreement[16], or (2) an obligor offers investors a new or restructured debt, or a new package of securities, cash or assets and the exchange has the effect of allowing the obligor to avoid a contractually-allowable payment omission as described in b) above[17].

The impairment status of a security may change over time as it migrates from impaired to cured (e.g., if initially deferred cumulative preferred dividends are ultimately paid in full) and possibly back again to impaired.

Definition of Loss-Given-Default

The loss-given-default rate for a security is 100% minus the value that is received at default resolution (which may occur at a single point in time or accrue over an interval of time), discounted by the coupon rate back to the date the last debt service payment was made, divided by the principal outstanding at the date of the last debt service payment.

In the special case of a distressed exchange default, when an investor is given new or modified securities in exchange, the LGD rate is 100% minus the trading value of the new securities received in exchange at the exchange date divided by the par value plus accrued interest of the original securities as of the exchange date.

13 For example, a debt security would become impaired when an obligor exercises a payment-in-kind option on a toggle bond. Examples of impairment events on non-debt securities include dividend omissions on preferred stock (both cumulative and non-cumulative), coupon omissions on other hybrid debt securities, and write downs or conversions to equity of contingent capital securities (CoCos). Excluded from impairment events are 1) missed payments due to purely technical or administrative errors which are not related to the ability or willingness to make the payments and 2) are cured in very short order (typically, 1-2 business days after the error is recognized).

14 Moody's studies of historical impairments are likely to focus on those impairments that are sustained and not cured. Among some structured finance asset classes, where cure rates within a 12-month time frame can be high, many impairments are not likely to be included in impairment studies.

15 Impairment distressed exchanges are similar to default distressed exchanges except that they have the effect of avoiding an impairment event, rather than a default event.

16 While contractually-allowable principal write-downs on structured finance securities are impairments, failures to pay principal as contractually required are defaults. Once written down, complete cures, in which securities are written back up to their original balances are extraordinarily rare; moreover, in most cases, a write-down of principal leads to an immediate and permanent loss of interest for investors, since the balance against which interest is calculated has been reduced.

17 Examples of such impairments include mandatory conversions of contingent capital securities to common equity and mandatory write-downs of other hybrid securities that are the direct result of obligor distress.

Long-Term Credit Ratings for Defaulted or Impaired Securities

When a debt instrument becomes impaired or defaults or is very likely to become impaired or to default, Moody's rating on that instrument will reflect our expectations for recovery of principal and interest, as well as the uncertainty around that expectation, as summarized in the table below.[18] Given the usual high level of uncertainty around recovery rate expectations, the table uses approximate expected recovery rates and is intended to present rough guidance rather than a rigid mapping.

Approximate Expected Recoveries Associated with Ratings for Defaulted or Impaired Securities

Expected Recovery Rate	Fundamental	Structured Finance
99 to 100%*	B1*	B1 (sf)*
97 to 99%*	B2*	B2 (sf)*
95 to 97%*	B3*	B3 (sf)*
90 to 95%	Caa1	Caa1 (sf)
80 to 90%	Caa2	Caa2 (sf)
65 to 80%	Caa3	Caa3 (sf)
35 to 65%	Ca	Ca (sf)
Less than 35%	C	C (sf)

* For instruments rated B1, B2, or B3, the uncertainty around expected recovery rates should also be low. For example, if a defaulted security has a higher than a 10% chance of recovering less than 90%, it would generally be rated lower than B3.

Additionally, the table may not apply directly in a variety of unusual circumstances. For example, a security in default where the default is likely to be fully cured over the short-term but remain very risky over a longer horizon might be rated much lower than suggested by this table. At the other end of the rating scale, very strong credits that experience temporary default events might be rated much higher than B1.[19] Under very rare circumstances a structured finance debt security may incur a one-time principal write-down that is very small (considerably less than 1% of par) and is not expected to recur.[20] In such cases, Moody's will add this small loss amount to its calculations of the expected loss associated with the security and may rate it higher than B1.

Securities in default where recovery rates are expected to be greater than 95% can be rated in the B category as outlined in the table above. In order to be assigned a rating in the single B category, the confidence level regarding the expected recovery rates should also be high. Or in other words, uncertainty should be low. As stated in the footnote to the table, if a security has a higher than a 10% chance of recovering less than 90%, then it would generally be rated lower than B3.

18 The approach to impairment is consistent with the approach to default. When an instrument is impaired or very likely to become impaired, the rating will reflect the expected loss relative to the value that was originally expected absent financial distress.

19 Additionally, payments missed for operational or technical reasons may not be classified as Moody's default events. See "Assessing the Rating Impact of Debt Payments That Are Missed for Operational or Technical Reasons", Moody's Special Comment, April 2013. Also, in certain circumstances an issuer of a structured finance security may delay an interest and/or principal payment beyond the relevant grace period due to a temporary delay in recovery or an operational problem. In such cases, Moody's will consider the potential increase in expected loss should interest not be paid on the delayed payment and may rate the security higher than B1.

20 For example, some master servicers of US RMBS implemented a new loan modification program and divided the cost of its administration across all their transactions, resulting in a loss of a few hundred dollars per security. In other examples some rated synthetic transactions have seen a very small loss attributable to the non payment of a very small CDS premium.

Credit Rating Methodologies

Credit Rating Methodologies describe the analytical framework MIS rating committees use to assign credit ratings. They set out the key analytical factors which MIS believes are the most important determinants of credit risk for the relevant sector. Methodologies are not exhaustive treatments of all factors reflected in MIS' ratings; they simply set out the key qualitative and quantitative considerations used by MIS in determining ratings. In order to help third parties understand MIS' analytical approach, all methodologies are publicly available.

Methodologies governing fundamental credits (e.g., non-financial corporates, financial institutions and governments) generally (though not always) incorporate a scorecard. A scorecard is a reference tool explaining the factors that are generally most important in assigning ratings. It is a summary, and does not contain every rating consideration. The weights shown for each factor and sub-factor in the scorecard represent an approximation of their typical importance for rating decisions, but the actual importance of each factor may vary significantly depending on the circumstances of the issuer and the environment in which it is operating. In addition, quantitative factor and sub-factor variables generally use historical data, but our rating analyses are based on forward-looking expectations. Each rating committee will apply its own judgment in determining whether and how to emphasize rating factors which it considers to be of particular significance given, for example, the prevailing operating environment. As a consequence, assigned ratings may fall outside the range or level indicated by the scorecard.

Methodologies governing structured finance credits often mention one or more rating models. A structured finance ratings model is a reference tool that explains how certain rating factors are considered in estimating a loss distribution for the collateral assets, or how the interplay between collateral cash flows, capital structure and credit enhancement jointly influence the credit risk of different tranches of securities. While methodologies may contain fixed values for key model parameters to be applied to transactions across an entire sector, individual rating committees are expected to employ judgment in determining model inputs, and rating committee deliberations may fall outside model-indicated outputs.

While most methodologies relate to a particular industry, sector or class of issuers or transactions, a small number — cross-sector methodologies, many originally issued as 'Rating Implementation Guidance' — have implications for a number of (and in some cases all) sectors. Examples include the methodologies which govern:

» the assignment of short-term ratings across the Fundamental Group;
» the use of credit estimates in the analysis of structured finance transactions;
» the linkage between sovereign ratings and related ratings in other Fundamental Groups;
» the 'notching' guidelines used to assign ratings to different classes of corporate debt;
» and the determination of country ceilings which cap domestic ratings.

Typically, these are broad commentaries, the output of which may be general guidance to committees on ranges or caps on ratings rather than a specific rating assignment and which, to a greater extent than sector-specific methodologies, set out broad principles and relationships rather than detailed risk factors which can be summarized in a scorecard. However, in other respects cross-sector methodologies are no different from any sector-specific methodology, in providing an analytical framework to promote consistency rather than a set of rules which must be applied rigidly in all circumstances.

Key Rating Assumptions

Methodologies may (but need not) contain separately identifiable key rating assumptions ("KRAs"). KRAs are the fixed inputs (sometimes expressed as a possible range of values) described in Credit Rating Methodologies such as mathematical or correlation assumptions which are common to broad classes of ratings, may be common to multiple Credit Rating Methodologies, and which inform rating committee judgments in assigning ratings across each class. KRAs are considered methodological and are subject to the same governance process as the methodology to which they relate, including the need for any changes to be approved by the relevant Policy Committee within MIS.

KRAs are, by their nature, relatively stable inputs to the analytical process, and because they seek to bring a degree of stability, consistency and transparency to something that may in practice be uncertain, they are intended to be reasonably resilient to change. They may change over time in response to long-term structural changes or as more is learned about long-run relationships between risk factors, but they would be very unlikely to change as a result of a short-run change in economic or financial market conditions.

By contrast, credit judgments reached in rating committees regarding the impact of prevailing credit conditions on ratings within a particular sector, country or region are not KRAs, even where those judgments affect a large number of Credit Ratings (for example because they alter a country ceiling, systemic support indicator or a Timely Payment Indicator). Moreover, rating committees will, from time to time, reach credit judgments in relation to the application of KRAs in the assignment of credit ratings for a particular deal or set of deals which are the subject of that rating committee, to reflect prevailing credit conditions in the relevant region or sub-sector (for example to apply higher or lower correlation assumptions while a given set of credit conditions persist). Such judgments would not be deemed to have amended a KRA, since they were not intended to be applied consistently and systematically across most if not all debt instruments covered by the relevant methodology, and in a manner which was largely insensitive to further changes in credit conditions. Macro-economic or financial market projections which are by definition specific to a particular point in time are not KRAs.

For Structured Finance Credit Rating Methodologies, KRAs are generally assumptions that underlie the overall methodological construct — values assigned to parameters which influence the analysis of a prototypical transaction broadly across the relevant sector. Examples would include:

» sector correlation assumptions;

» loss severity assumptions for particular sectors;

» and idealized default rates when used as a proxy for collateral performance.

Inputs to the rating of structured finance transactions that result from credit judgments reached by rating committees or which reflect analytic deliberations and that are not KRAs include, for example:

» the credit risk considerations (as reflected in credit ratings or other credit assessments) introduced by third parties, such as guarantors and other support providers, servicers, trust banks, swap providers, etc.;

» the credit risk introduced by the issuer's operating environment, as reflected, for example, by bond and deposit ceilings;

» changes in collateral asset risk expectations brought on by changes in the economic environment; and

» the maximum extent to which a bank's legal and operating environment would enable overcollateralization to provide lift for a covered bond's rating over the bank's own rating, as expressed in the Timely Payment Indicator.

For Fundamental Credit Rating Methodologies, KRAs are intrinsically less common (in part reflecting the less quantitative nature of Fundamental credit analysis), and where they do exist they may be embedded within the underlying Credit Rating Methodology. Generally, they are so deeply embedded in the overlying analytical structure that it would be meaningless and misleading to identify them as distinct from the Credit Rating Methodology itself: a KRA change would almost inevitably involve a corresponding change to the Credit Rating Methodology itself. Examples of deeply embedded KRAs in Fundamental that cannot be viewed distinctly from a Credit Rating Methodology include:

- the assumption that leverage and access to liquidity are strong drivers of credit risk and appropriate factors to include in Credit Rating Methodologies;
- the assumptions that there is very strong interdependence between bank and sovereign credit strength (from which MIS concludes that a lower-rated sovereign cannot generally provide ratings lift through support to a higher rated bank);
- the assumption that legal priority of claim affects average recovery on different classes of debt sufficiently to warrant higher or lower ratings for different classes of debt;
- and the assumption that sovereign credit risk is strongly correlated with that of other domestic issuers.

Examples of assumptions in Fundamental Credit Rating Methodologies that would be considered KRAs distinct from (though perhaps stated in) the Credit Rating Methodology to which each relates would include:

- loss severity assumptions for different sectors;
- and idealized loss rates when used as a proxy for the ability of a sovereign to support its banking system;

Inputs to the fundamental ratings process that result from credit judgments reached by rating committees or which reflect analytic deliberations which are not KRAs include:

- the credit risk considerations (as reflected in credit ratings or other credit assessments) introduced by third parties, such as guarantors and other support providers or affiliates;
- the credit risk introduced by the issuer's operating environment, as reflected, for example, by bond and deposit ceilings; and
- the ability a sovereign to provide support to, for example, banks, as expressed in a systemic support indicator.
- Such inputs may incorporate underlying assumptions which may be KRAs.

Country Ceilings for Bonds and Other Foreign Currency Obligations

Moody's assigns long-term and short-term ceilings for foreign-currency bonds and notes to every country (or separate monetary area) in which there are rated obligors. The ceilings generally indicate the highest ratings that can be assigned to a foreign-currency denominated security issued by an entity subject to the monetary sovereignty of that country or area. Ratings that pierce the country ceilings may be permitted, however, for foreign-currency denominated securities benefiting from special characteristics that are judged to give them a lower risk of government interference than is indicated by the ceilings. Such characteristics may be intrinsic to the issuer and/or related to Moody's view regarding the government's likely policy actions during a foreign currency crisis. The country ceilings for foreign-currency bonds and notes are expressed on Moody's long-term and short-term global scales.

Country Ceilings for Foreign Currency Bank Deposits

Moody's assigns long-term and short-term ceilings for foreign-currency bank deposits to every country (or distinct monetary area) in which there are rated bank deposits. The ceilings specify the highest ratings that can be assigned to foreign-currency denominated deposit obligations of 1) domestic and foreign branches of banks headquartered in that domicile (even if subsidiaries of foreign banks); and 2) domestic branches of foreign banks. The country ceilings for foreign-currency bank deposits are expressed on Moody's long-term and short-term global scales.

Country Ceiling for Bonds and Other Local Currency Obligations

Moody's assigns a local currency ceiling for bonds and notes to every country (or distinct monetary areas) in order to facilitate the assignment of local currency ratings to issues and/or issuers. Local currency ratings measure the credit performance of obligations denominated in the local currency and therefore exclude the transfer risk relevant for foreign-currency obligations. They are intended to be globally comparable.

The local currency country ceiling for bonds summarizes the general country-level risks (excluding foreign-currency transfer risk) that should be taken into account in assigning local currency ratings to locally domiciled obligors or locally originated structured transactions. They indicate the rating level that will generally be assigned to the financially strongest obligations in the country, with the proviso that obligations benefiting from support mechanisms based outside the country (or area) may on occasion be rated higher. The country ceiling for local currency bonds and notes is expressed on the long-term global scale.

Local Currency Deposit Ceiling

Moody's Local Currency Deposit Ceiling for a country or monetary region is the highest rating that can be assigned to the local currency deposits of a bank or other deposit taking institution domiciled within that rated jurisdiction. It reflects the risk that governmental authorities might impose a freeze on all local currency bank deposits in the system in response to a systemic run on deposits or a heightened risk of such a run. The local currency deposit ceiling is expressed on the long-term global scale.

Hybrid Security Baskets

In determining equity credit for a hybrid security, Moody's analyzes the instrument along three dimensions of equity: No Maturity, No Ongoing Payments, and Loss Absorption. For each of these dimensions, Moody's ranks the instrument's features as either None, Weak, Moderate, or Strong, where None represents more debt-like and Strong represents more equity-like. The equity credit assigned to the instrument — expressed in baskets from A to E — weights the rankings for each dimension depending on the credit quality of the issuer.

Hybrid Baskets

Basket	Debt	Equity
A	100%	0%
B	75%	25%
C	50%	50%
D	25%	75%
E	0%	100%

Timely Payment Indicator (TPI)

A TPI is Moody's assessment of the likelihood that timely payment would be made to covered bondholders following an Issuer Default. TPIs are assigned one of the following six assessment levels: Very High, High, Probable-High, Probable, Improbable, Very Improbable.

Idealized Probabilities of Default and Expected Losses

For some obligations and asset classes we may use benchmark default probabilities and expected losses as input into rating models and other aspects of ratings analytics. These default probabilities and expected loss rates are referred to as Moody's Idealized Probabilities of Default and Moody's Idealized Expected Losses, respectively. Tables containing Moody's Idealized Default Probabilities and Expected Losses can be found here: Moody's Idealized Default and Loss Rates

These tables were derived from the corporate default and loss experience observed between 1970 and 1989, with several key adjustments, such as interpolation to help fill in gaps arising from lack of alpha-numeric rating (i.e. A2 vs. A3) default and loss rates prior to April 1983.

We note that while we use the idealized default and loss rates in models used in the rating process, the performance of ratings is benchmarked against past performance and rating performance in other sectors rather than against any idealized table.

PAGE INTENTIONALLY LEFT BLANK

PAGE INTENTIONALLY LEFT BLANK

For further information contact us at a location below:

Americas
+1.212.553.1653
clientservices@moodys.com

EMEA
+44.20.7772.5454
clientservices@moodys.com

Asia-Pacific
+852.3551.3077
clientservices@moodys.com

Japan
+81.3.5408.4100
clientservices@moodys.com

MOODY'S
INVESTORS SERVICE

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's downgrades OGE to Baa1 and Oklahoma Gas & Electric to A2; outlooks remain negative

05 Jul 2018

Approximately $3 billion of debt securities affected

New York, July 05, 2018 -- Moody's Investors Service ("Moody's") today downgraded the long-term ratings of OGE Energy Corp. (OGE, senior unsecured to Baa1 from A3) and its primary operating subsidiary, Oklahoma Gas & Electric Company (OG&E, senior unsecured to A2 from A1) due to weakened financial metrics at OG&E, resulting from stagnant cash flow at a time when debt is rising to fund capital projects. The short-term ratings of both companies, including OGE's P-2 commercial paper rating, OG&E's P-1 commercial paper rating and OG&E's VMIG 1 rating, were affirmed. The outlooks for both companies remain negative due to the potential for a sustained reduction in financial metrics beyond the next 12-18 months.

Downgrades:

..Issuer: Garfield (County of) OK, Industrial Authority

....Senior Unsecured Revenue Bonds, Downgraded to A2 from A1

..Issuer: Muskogee (Cnty of) OK, Industrial Trust

....Senior Unsecured Revenue Bonds, Downgraded to A2 from A1

..Issuer: OGE Energy Corp.

....Senior Unsecured Bank Credit Facility, Downgraded to Baa1 from A3

....Senior Unsecured Shelf, Downgraded to (P)Baa1 from (P)A3

..Issuer: Oklahoma Gas & Electric Company

.... Issuer Rating, Downgraded to A2 from A1

....Senior Unsecured Bank Credit Facility, Downgraded to A2 from A1

....Senior Unsecured Regular Bond/Debenture, Downgraded to A2 from A1

....Senior Unsecured Shelf, Downgraded to (P)A2 from (P)A1

Outlook Actions:

..Issuer: OGE Energy Corp.

....Outlook, Remains Negative

..Issuer: Oklahoma Gas & Electric Company

....Outlook, Remains Negative

Affirmations:

..Issuer: Garfield (County of) OK, Industrial Authority

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: Muskogee (Cnty of) OK, Industrial Trust

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: OGE Energy Corp.

.... Commercial Paper, Affirmed P-2

..Issuer: Oklahoma Gas & Electric Company

....Senior Unsecured Commercial Paper, Affirmed P-1

RATINGS RATIONALE

"OG&E's financial strength is declining due to cash flow growth that isn't keeping pace with rising debt levels" said Ryan Wobbrock, Vice President -- Senior Analyst. "With debt increasing to fund environmental projects as we had anticipated, the cash flow recovery that we had expected will not materialize given the results of OG&E's last two rate cases. This will keep OG&E's cash flow to debt ratios below 25% through 2020" he added.

Parent OGE's downgrade follows that of OG&E, since the utility provides over 80% of consolidated cash flow and represents OGE's core holding.

Since 2015, OG&E has been increasing its capital spending in order to reduce its overall emissions profile, with roughly $2.1 billion in total capital expenditures through LTM 1Q18. During this spending phase, we had expected that a series of consecutive rate filings would begin to compensate OG&E for the investments and that the utility would ultimately produce cash flow to debt ratios of 27% or better. However, the outcome of OG&E's recent general rate cases and the implementation of 2017 federal tax reform (reflected in the company's June 2018 rate settlement) will keep OG&E's ratio of cash flow to debt between 20% and 25% through 2020.

The negative outlook on OG&E reflects the potential for financial metrics to remain suppressed beyond 2020; for example, sustained cash flow to debt around 20%, rather than increasing toward 25% from incremental rate increases. This could be the result of cost recovery that lags operating and capital expenses in 2019 and beyond. OG&E's next scheduled rate case is expected later this year and will primarily seek to recover scrubber installation costs at the roughly 1,000 megawatt Sooner coal-fired generation plant (Sooner), to be completed by year-end 2018. No other rate case is being contemplated at this time.

OGE's downgrade and negative outlook reflect key subsidiary OG&E's credit momentum, since the holding company is structurally subordinated to OG&E, its primary subsidiary. Its rating also incorporates notching considerations for the higher business risk associated with its 25.6% limited partner interest Enable Midstream Partners, LP (Baa3 stable). Enable is a master limited partnership (MLP) engaged in natural gas gathering, processing and transportation. The MLP's annual distributions constitute roughly 15%-20% of OGE's consolidated cash flow from operations (CFO).

Moody's also analyzes OGE's credit from a proportionate consolidation perspective, assuming 25.6% of Enable's cash flow and debt is attributed to OGE, while removing the CFO contribution of Enable's dividends. This sensitivity results in OGE generating cash flow to debt ratios in the high-teens (e.g., 18%) on a consistent basis.

OG&E's December 2015 rate case took about 15 months between the filing and the Oklahoma Corporation Commission (OCC) order and resulted in less cash flow from depreciation and at a lower authorized ROE than what had been previously incorporated into rates. The recently approved June rate settlement on OG&E's latest rate case will reduce base rates by $64 million and pressure cash flow further. While there are positive structural components to the rate settlement (e.g., regulatory asset treatment for scrubber installation at Sooner and a production tax credit rider), the negative cash flow impact of federal tax reform will overshadow the positive cash flow impact that we originally expected as a result of a higher rate base.

Factors that could lead to a downgrade

OG&E could be downgraded if there is no evidence of a rebound in key ratios beyond the next 12-18 months. For example, cash flow to debt persisting below 25%, on an ongoing basis, would add further negative ratings pressure. Also, if the credit supportiveness of the regulatory relationship and cost recovery provisions were to decline, OG&E's rating could be downgraded.

OGE would be likely downgraded if any of the following were to occur: 1) a downgrade of OG&E, 2) if consolidated cash flow to debt falls to around 20% (or below 18% when proportionately consolidating Enable),

3) if the risk profile of OGE's subsidiaries were to increase substantially, or 4) if OGE adds a material amount of holding company leverage.

Factors that could lead to an upgrade

Since both companies have a negative outlook, it is unlikely that either OG&E or OGE will be upgraded over the next 12-18 months.

However, OG&E could be upgraded with cash flow to debt consistently above 27% and if cost recovery and other regulatory provisions in Oklahoma improve.

OGE could be upgraded if OG&E is upgraded and if consolidated cash flow to debt consistently exceeds 25%, and 22% proportionate consolidated basis. Also, a material reduction in business risk exposure could result in OGE's rating being more closely aligned to that of OG&E.

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in June 2017. Please see the Rating Methodologies page on www.moodys.com for a copy of this methodology.

REGULATORY DISCLOSURES

For ratings issued on a program, series or category/class of debt, this announcement provides certain regulatory disclosures in relation to each rating of a subsequently issued bond or note of the same series or category/class of debt or pursuant to a program for which the ratings are derived exclusively from existing ratings in accordance with Moody's rating practices. For ratings issued on a support provider, this announcement provides certain regulatory disclosures in relation to the credit rating action on the support provider and in relation to each particular credit rating action for securities that derive their credit ratings from the support provider's credit rating. For provisional ratings, this announcement provides certain regulatory disclosures in relation to the provisional rating assigned, and in relation to a definitive rating that may be assigned subsequent to the final issuance of the debt, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive rating in a manner that would have affected the rating. For further information please see the ratings tab on the issuer/entity page for the respective issuer on www.moodys.com.

For any affected securities or rated entities receiving direct credit support from the primary entity(ies) of this credit rating action, and whose ratings may change as a result of this credit rating action, the associated regulatory disclosures will be those of the guarantor entity. Exceptions to this approach exist for the following disclosures, if applicable to jurisdiction: Ancillary Services, Disclosure to rated entity, Disclosure from rated entity.

Regulatory disclosures contained in this press release apply to the credit rating and, if applicable, the related rating outlook or rating review.

Please see www.moodys.com for any updates on changes to the lead rating analyst and to the Moody's legal entity that has issued the rating.

Please see the ratings tab on the issuer/entity page on www.moodys.com for additional regulatory disclosures for each credit rating.

Ryan Wobbrock
Vice President - Senior Analyst
Infrastructure Finance Group
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

Jim Hempstead
MD - Utilities
Infrastructure Finance Group
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

Releasing Office:
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

MOODY'S is not an auditor and cannot in every instance independently verify or validate information received in the rating process or in preparing the Moody's publications.

To the extent permitted by law, MOODY'S and its directors, officers, employees, agents, representatives, licensors and suppliers disclaim liability to any person or entity for any indirect, special, consequential, or incidental losses or damages whatsoever arising from or in connection with the information contained herein or the use of or inability to use any such information, even if MOODY'S or any of its directors, officers, employees, agents, representatives, licensors or suppliers is advised in advance of the possibility of such losses or damages, including but not limited to: (a) any loss of present or prospective profits or (b) any loss or damage arising where the relevant financial instrument is not the subject of a particular credit rating assigned by MOODY'S.

To the extent permitted by law, MOODY'S and its directors, officers, employees, agents, representatives, licensors and suppliers disclaim liability for any direct or compensatory losses or damages caused to any person or entity, including but not limited to by any negligence (but excluding fraud, willful misconduct or any other type of liability that, for the avoidance of doubt, by law cannot be excluded) on the part of, or any contingency within or beyond the control of, MOODY'S or any of its directors, officers, employees, agents, representatives, licensors or suppliers, arising from or in connection with the information contained herein or the use of or inability to use any such information.

NO WARRANTY, EXPRESS OR IMPLIED, AS TO THE ACCURACY, TIMELINESS, COMPLETENESS, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OF ANY SUCH RATING OR OTHER OPINION OR INFORMATION IS GIVEN OR MADE BY MOODY'S IN ANY FORM OR MANNER WHATSOEVER.

Moody's Investors Service, Inc., a wholly-owned credit rating agency subsidiary of Moody's Corporation ("MCO"), hereby discloses that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by Moody's Investors Service, Inc. have, prior to assignment of any rating, agreed to pay to Moody's Investors Service, Inc. for appraisal and rating services rendered by it fees ranging from $1,500 to approximately $2,500,000. MCO and MIS also maintain policies and procedures to address the independence of MIS's ratings and rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold ratings from MIS and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually at www.moodys.com under the heading "Investor Relations — Corporate Governance — Director and Shareholder Affiliation Policy."

Additional terms for Australia only: Any publication into Australia of this document is pursuant to the Australian Financial Services License of MOODY'S affiliate, Moody's Investors Service Pty Limited ABN 61 003 399 657AFSL 336969 and/or Moody's Analytics Australia Pty Ltd ABN 94 105 136 972 AFSL 383569 (as applicable). This document is intended to be provided only to "wholesale clients" within the meaning of section 761G of the Corporations Act 2001. By continuing to access this document from within Australia, you represent to MOODY'S that you are, or are accessing the document as a representative of, a "wholesale client" and that neither you nor the entity you represent will directly or indirectly disseminate this document or its contents to "retail clients" within the meaning of section 761G of the Corporations Act 2001. MOODY'S credit rating is an opinion as to the creditworthiness of a debt obligation of the issuer, not on the equity securities of the issuer or any form of security that is available to retail investors. It would be reckless and inappropriate for retail investors to use MOODY'S credit ratings or publications when making an investment decision. If in doubt you should contact your financial or other professional adviser.

Additional terms for Japan only: Moody's Japan K.K. ("MJKK") is a wholly-owned credit rating agency subsidiary of Moody's Group Japan G.K., which is wholly-owned by Moody's Overseas Holdings Inc., a wholly-owned subsidiary of MCO. Moody's SF Japan K.K. ("MSFJ") is a wholly-owned credit rating agency subsidiary of MJKK. MSFJ is not a Nationally Recognized Statistical Rating Organization ("NRSRO"). Therefore, credit ratings assigned by MSFJ are Non-NRSRO Credit Ratings. Non-NRSRO Credit Ratings are assigned by an entity that is not a NRSRO and, consequently, the rated obligation will not qualify for certain types of treatment under U.S. laws. MJKK and MSFJ are credit rating agencies registered with the Japan Financial Services Agency and their registration numbers are FSA Commissioner (Ratings) No. 2 and 3 respectively.

MJKK or MSFJ (as applicable) hereby disclose that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by MJKK or MSFJ (as applicable) have, prior to assignment of any rating, agreed to pay to MJKK or MSFJ (as applicable) for appraisal and rating services rendered by it fees ranging from JPY200,000 to approximately JPY350,000,000.

MJKK and MSFJ also maintain policies and procedures to address Japanese regulatory requirements.

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's downgrades ConEd to Baa1, CECONY to A3 and O&R to Baa1; outlooks stable

30 Oct 2018

New York, October 30, 2018 -- Moody's Investors Service ("Moody's") today downgraded the long-term ratings of Consolidated Edison, Inc. (ConEd, senior unsecured to Baa1 from A3) and its subsidiaries Consolidated Edison Company of New York, Inc. (CECONY, senior unsecured to A3 from A2) and Orange and Rockland Utilities, Inc. (O&R, senior unsecured to Baa1 from A3) due to a weaker financial profile. Moody's also downgraded CECONY's short-term commercial paper rating to P-2 from P-1. The P-2 commercial paper ratings for ConEd and O&R were affirmed. See a full debt list of affected ratings at the end of this press release. The outlooks for ConEd, CECONY and O&R are stable.

RATINGS RATIONALE

"ConEd's financial profile is weaker due to cash flow headwinds from tax reform, coupled with incremental holding company debt" said Ryan Wobbrock, Vice President -- Senior Analyst. "We see ConEd's ratio of consolidated cash flow to debt falling to around 15%, down from over 20% historically" added Wobbrock.

ConEd's credit is primarily driven by CECONY, since the utility represents roughly 90% of consolidated cash flow. In August, CECONY received some clarity on rate treatment of tax reform via a New York Public Service Commission (NYPSC) order, which includes sur-credits for electric and gas revenue in 2019 and amortization of accumulated deferred tax benefits to be determined in an upcoming general rate case. This means that CECONY will have a series of revenue and cash flow reductions that will offset some of the expected general rate increases that the utility would otherwise have.

As such, we expect CECONY's cash flow to remain steady, at the same time that the utility's capital spending -- and debt - is expected to increase for infrastructure resiliency, energy efficiency and other New York policy priorities. The combination will result in CECONY cash flow to debt ratios around 16-17% through 2020, which is also down from over 20% in recent years.

O&R faces the same type of cash flow headwinds and rate treatment as CECONY, which will reduce currently strong ratios of cash flow from operations before working capital (CFO pre-WC) to debt of over 20% to the mid-teen's over the next 2-3 years.

ConEd's financial decline reflects that of its utility subsidiaries and will be exacerbated by its intent to issue around $825 million of incremental amortizing debt as part of a 981 megawatt (MW) of renewable generation assets purchase. The $2.1 billion purchase, of mostly solar electric generation assets, includes the assumption of roughly $576 million of project level debt. This will increase the amount of ConEd's non-utility debt to around 16% of consolidated debt, from almost 13%, based on June 30 amounts.

ConEd's credit is supported by its ownership of rate regulated utility operations in transparent and supportive regulatory environments. It's unregulated business exposure remains relatively low, at just above 10% of expected 2019 consolidated EBITDA, and is backed by contracted revenue with credit-worthy counterparties.

The credit profiles of CECONY and O&R reflect their low business risk electric and gas (and steam, for CECONY) transmission and distribution assets that benefit from a suite of timely cost recovery mechanisms. These mechanisms allow the companies to generate stable and predictable cash flow and earned returns.

Factors that Could Lead to an Upgrade

Material improvements to financial metrics could lead to upgrades for ConEd, CECONY and O&R. This could occur with better than anticipated regulatory outcomes that drive sustainable CFO pre-WC to debt ratios to around 20% for ConEd, the low-to-mid 20% range for CECONY and at least 19% for O&R.

Factors that Could Lead to a Downgrade

ConEd could be downgraded if CECONY is downgraded, if unregulated operations become riskier and grow to

15-20% of consolidated EBITDA, or if incremental parent-debt results in CFO pre-WC to debt consistently below 15%.

CECONY could be downgraded if regulatory support declines or if CFO pre-WC to debt declines consistently below 17%.

O&R could be downgraded if regulatory support declines or if CFO pre-WC to debt declines consistently to around 15%.

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in June 2017. Please see the Rating Methodologies page on www.moodys.com for a copy of this methodology.

Downgrades:

..Issuer: Consolidated Edison Company of New York, Inc.

.... Issuer Rating, Downgraded to A3 from A2

....Senior Unsecured Commercial Paper, Downgraded to P-2 from P-1

....Senior Unsecured Regular Bond/Debenture, Downgraded to A3 from A2

....Underlying Senior Unsecured Regular Bond/Debenture, Downgraded to A3 from A2

..Issuer: Consolidated Edison, Inc.

.... Issuer Rating, Downgraded to Baa1 from A3

....Senior Unsecured Shelf, Downgraded to (P)Baa1 from (P)A3

....Senior Unsecured Regular Bond/Debenture, Downgraded to Baa1 from A3

..Issuer: New York State Energy Research & Dev. Auth.

....Senior Unsecured Revenue Bonds, Downgraded to A3 from A2

....Underlying Senior Unsecured Revenue Bonds, Downgraded to A3 from A2

..Issuer: New York State Research & Development Auth.

....Senior Unsecured Revenue Bonds, Downgraded to A3 from A2

....Underlying Senior Unsecured Revenue Bonds, Downgraded to A3 from A2

..Issuer: Orange and Rockland Utilities, Inc.

.... Issuer Rating, Downgraded to Baa1 from A3

....Senior Unsecured Regular Bond/Debenture, Downgraded to Baa1 from A3

Outlook Actions:

..Issuer: Consolidated Edison Company of New York, Inc.

....Outlook, Changed To Stable From Negative

..Issuer: Consolidated Edison, Inc.

....Outlook, Changed To Stable From Negative

..Issuer: Orange and Rockland Utilities, Inc.

....Outlook, Changed To Stable From Negative

Affirmations:

..Issuer: Consolidated Edison, Inc.

....Senior Unsecured Commercial Paper, Affirmed P-2

..Issuer: Orange and Rockland Utilities, Inc.

....Senior Unsecured Commercial Paper, Affirmed P-2

REGULATORY DISCLOSURES

For ratings issued on a program, series or category/class of debt, this announcement provides certain regulatory disclosures in relation to each rating of a subsequently issued bond or note of the same series or category/class of debt or pursuant to a program for which the ratings are derived exclusively from existing ratings in accordance with Moody's rating practices. For ratings issued on a support provider, this announcement provides certain regulatory disclosures in relation to the credit rating action on the support provider and in relation to each particular credit rating action for securities that derive their credit ratings from the support provider's credit rating. For provisional ratings, this announcement provides certain regulatory disclosures in relation to the provisional rating assigned, and in relation to a definitive rating that may be assigned subsequent to the final issuance of the debt, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive rating in a manner that would have affected the rating. For further information please see the ratings tab on the issuer/entity page for the respective issuer on www.moodys.com.

For any affected securities or rated entities receiving direct credit support from the primary entity(ies) of this credit rating action, and whose ratings may change as a result of this credit rating action, the associated regulatory disclosures will be those of the guarantor entity. Exceptions to this approach exist for the following disclosures, if applicable to jurisdiction: Ancillary Services, Disclosure to rated entity, Disclosure from rated entity.

Regulatory disclosures contained in this press release apply to the credit rating and, if applicable, the related rating outlook or rating review.

Please see www.moodys.com for any updates on changes to the lead rating analyst and to the Moody's legal entity that has issued the rating.

Please see the ratings tab on the issuer/entity page on www.moodys.com for additional regulatory disclosures for each credit rating.

Ryan Wobbrock
Vice President - Senior Analyst
Infratructure Finance Group
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

Jim Hempstead
MD - Utilities
Infrastructure Finance Group
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

Releasing Office:
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

arising where the relevant financial instrument is not the subject of a particular credit rating assigned by MOODY'S.

To the extent permitted by law, MOODY'S and its directors, officers, employees, agents, representatives, licensors and suppliers disclaim liability for any direct or compensatory losses or damages caused to any person or entity, including but not limited to by any negligence (but excluding fraud, willful misconduct or any other type of liability that, for the avoidance of doubt, by law cannot be excluded) on the part of, or any contingency within or beyond the control of, MOODY'S or any of its directors, officers, employees, agents, representatives, licensors or suppliers, arising from or in connection with the information contained herein or the use of or inability to use any such information.

NO WARRANTY, EXPRESS OR IMPLIED, AS TO THE ACCURACY, TIMELINESS, COMPLETENESS, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OF ANY SUCH RATING OR OTHER OPINION OR INFORMATION IS GIVEN OR MADE BY MOODY'S IN ANY FORM OR MANNER WHATSOEVER.

Moody's Investors Service, Inc., a wholly-owned credit rating agency subsidiary of Moody's Corporation ("MCO"), hereby discloses that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by Moody's Investors Service, Inc. have, prior to assignment of any rating, agreed to pay to Moody's Investors Service, Inc. for appraisal and rating services rendered by it fees ranging from $1,500 to approximately $2,500,000. MCO and MIS also maintain policies and procedures to address the independence of MIS's ratings and rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold ratings from MIS and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually at www.moodys.com under the heading "Investor Relations — Corporate Governance — Director and Shareholder Affiliation Policy."

Additional terms for Australia only: Any publication into Australia of this document is pursuant to the Australian Financial Services License of MOODY'S affiliate, Moody's Investors Service Pty Limited ABN 61 003 399 657AFSL 336969 and/or Moody's Analytics Australia Pty Ltd ABN 94 105 136 972 AFSL 383569 (as applicable). This document is intended to be provided only to "wholesale clients" within the meaning of section 761G of the Corporations Act 2001. By continuing to access this document from within Australia, you represent to MOODY'S that you are, or are accessing the document as a representative of, a "wholesale client" and that neither you nor the entity you represent will directly or indirectly disseminate this document or its contents to "retail clients" within the meaning of section 761G of the Corporations Act 2001. MOODY'S credit rating is an opinion as to the creditworthiness of a debt obligation of the issuer, not on the equity securities of the issuer or any form of security that is available to retail investors. It would be reckless and inappropriate for retail investors to use MOODY'S credit ratings or publications when making an investment decision. If in doubt you should contact your financial or other professional adviser.

Additional terms for Japan only: Moody's Japan K.K. ("MJKK") is a wholly-owned credit rating agency subsidiary of Moody's Group Japan G.K., which is wholly-owned by Moody's Overseas Holdings Inc., a wholly-owned subsidiary of MCO. Moody's SF Japan K.K. ("MSFJ") is a wholly-owned credit rating agency subsidiary of MJKK. MSFJ is not a Nationally Recognized Statistical Rating Organization ("NRSRO"). Therefore, credit ratings assigned by MSFJ are Non-NRSRO Credit Ratings. Non-NRSRO Credit Ratings are assigned by an entity that is not a NRSRO and, consequently, the rated obligation will not qualify for certain types of treatment under U.S. laws. MJKK and MSFJ are credit rating agencies registered with the Japan Financial Services Agency and their registration numbers are FSA Commissioner (Ratings) No. 2 and 3 respectively.

MJKK or MSFJ (as applicable) hereby disclose that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by MJKK or MSFJ (as applicable) have, prior to assignment of any rating, agreed to pay to MJKK or MSFJ (as applicable) for appraisal and rating services rendered by it fees ranging from JPY200,000 to approximately JPY350,000,000.

MJKK and MSFJ also maintain policies and procedures to address Japanese regulatory requirements.

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's changes Xcel Energy's outlook to negative; downgrades Southwestern Public Service ratings to Baa2 with stable outlook

19 Oct 2018

Approximately $19 billion of debt securities affected

New York, October 19, 2018 -- Moody's Investors Service ("Moody's") changed the rating outlook of Xcel Energy Inc. (Xcel) to negative from stable and affirmed the A3 senior unsecured and Prime-2 short-term rating for commercial paper ratings.

At the same time, Moody's downgraded the long-term ratings of Southwestern Public Service Company (SPS) including the Issuer rating to Baa2 from Baa1 and affirmed SPS' P-2 short-term rating. The outlook for SPS was changed to stable from negative.

Moody's also affirmed the ratings and outlooks of the Xcel other rated subsidiaries: Northern States Power Company (Minnesota) (NSP-Minnesota, A2 stable), Public Service Company of Colorado (PSCO, A3 stable), and Northern States Power Company (Wisconsin) (NSP-Wisconsin, A2 stable).

RATINGS RATIONALE

"Xcel Energy's financial ratios will be lower for longer due to the cash flow leakage associated with tax reform and an elevated investment program primarily funded with debt" said Natividad Martel, Vice President - Senior Analyst. "The negative outlook reflects consolidated cash flow to debt ratios falling to the 16%-17% range over the next few years, down from around 20% over the last several years."

Xcel's A3 rating factors the group's fully regulated operations and its geographic and operational diversity benefits, as well as our view that the eight regulatory jurisdictions in which its four utility subsidiaries operate are overall credit supportive. The rating considers Xcel's improving carbon transition risk exposure, with an accelerating "steel for fuel" program where the company is replacing fossil-fired generation with renewable generation. The rating also factors in the $300 million equity issuance initiated September 2018 and the structurally subordinated position of the parent level debt vis-à-vis the debt outstanding at its utility subsidiaries, with holding company debt relative to total consolidated debt expected to remain below 25% (currently around 22%).

Southwestern Public Service Company (SPS)

The downgrade of SPS' ratings reflects a weakening in the utility's credit metrics, such that its ratio of CFO pre-W/C to debt is anticipated to drop to nearly 16% by next year, a material deterioration compared to the 22% ratio that SPS generated for the last twelve month period ended 30 June 2018. SPS' Baa2 rating and stable outlook incorporate the expectation that its CFO pre-W/C to debt ratio will remain in the 16%-17% range over the foreseeable future. The Baa2 rating considers our mixed view of the credit supportiveness of the regulatory environments under which SPS operates. Moody's sees more constructive recovery mechanisms available in Texas than in New Mexico, illustrated by the different regulators' responses to the utility's initiatives to offset the impact of the implementation of the TCJA. In Texas, the regulators approved the multi-party settlement that included authorization to earn a 9.5% rate on equity (ROE) on SPS' actual capital structure, which the utility anticipates will include an above average 57% equity layer. In contrast, the New Mexico Regulatory Commission approved, in September 2018, an increase in SPS' base rates ($8 million) based on a 51% equity ratio, a significant difference compared to SPS' requested 58% equity ratio. This request was updated post-tax reform, and could be indicating a less constructive relationship between the utility and the NMPRC. The combination of the utilities' investment program along with the exposure of its cash flows to regulatory lag, particularly due to the absence of any transmission and distribution riders in New Mexico, contribute to the extended deterioration in the utility's financial profile.

NSP-Minnesota, PSCO and NSP-Wisconsin

The affirmation of the ratings of NSP-Minnesota (A2, stable), NSP-Wisconsin (A2 stable) and PSCO (A3 stable) consider our view that all three utilities maintain a reasonably constructive relationship with their respective regulators. The rating affirmations incorporate the expectation that the outcomes of pending regulatory decisions, including the need to address tax reform cash flows, will be a net credit positive. In some states, these measures include the deferral of portions of the excess deferred tax liabilities (EDTL) to be refunded to end-users. In Colorado, PSCO was allowed to amortize prepaid pension assets as an offset of refunds in 2018 and 2019. PSCO has also requested an increase in its the equity ratio to 56% in the Colorado natural gas TCJA true-up proceeding with the decision expected later this year. The stable outlooks assume that these regulatory initiatives along with the reduction in the utilities' base case investments will help to partially mitigate the anticipated weakening in the credit metrics. Importantly, the stable outlooks also assume that each of these utilities will continue to generate CFO pre-W/C to debt in excess of 20%, on a sustained basis.

WHAT CAN CHANGE THE RATING - DOWN

Xcel's ratings could be downgraded if the consolidated ratio of CFO pre-W/C to debt remains below 18% for a sustained basis, or there is no transparent path to improve the ratio over the next few years. The ratings of NSP-Minnesota, NSP-Wisconsin, PSCO and SPS could be downgraded if we perceive a deterioration in the credit supportiveness of their regulatory environments, or if their credit metrics deteriorate more than currently anticipated. Specifically, downward pressure on the ratings of NSP-Minnesota and NSP-Wisconsin could result if their CFO pre-W/C to debt ratios fall to the low 20% range, for an extended period.

In the case of PSCO and SPS, producing CFO pre-W/C to debt below 20% and 16%, respectively, on a sustained basis, is also likely to result in a downgrade of their ratings.

WHAT CAN CHANGE THE RATING - UP

Given Xcel's negative outlook, there are limited prospects for a near term upgrade. However, the outlook could be stabilized if we see a clear path for Xcel to record again CFO pre-W/C to debt in excess of 18%, on a sustained basis.

Positive momentum on the ratings of NSP-Minnesota, NSP-Wisconsin, PSCO and SPS is also unlikely given our expectation that their weakening credit metrics will result in their credit profiles to be commensurate with their current ratings. Longer term, the utilities' ratings could experience positive momentum if higher than anticipated regulatory relief and/or cost savings allow them to record CFO pre-W/C to debt in the high 20% in the case of NSP-Minnesota and NSP-Wisconsin, 25% in the case of PSCO, and 18% in the case of SPS.

Downgrades:

..Issuer: Southwestern Public Service Company

.... Issuer Rating, Downgraded to Baa2 from Baa1

....Senior Secured Shelf, Downgraded to (P)A3 from (P)A2

....Senior Unsecured Shelf, Downgraded to (P)Baa2 from (P)Baa1

....Senior Secured First Mortgage Bonds, Downgraded to A3 from A2

....Senior Unsecured Bank Credit Facility, Downgraded to Baa2 from Baa1

....Senior Unsecured Regular Bond/Debenture, Downgraded to Baa2 from Baa1

Outlook Actions:

..Issuer: Northern States Power Company (Minnesota)

....Outlook, Remains Stable

..Issuer: Northern States Power Company (Wisconsin)

....Outlook, Remains Stable

..Issuer: Public Service Company of Colorado

....Outlook, Remains Stable

..Issuer: Southwestern Public Service Company

....Outlook, Changed To Stable From Negative

..Issuer: Xcel Energy Inc.

....Outlook, Changed To Negative From Stable

Affirmations:

..Issuer: La Crosse (City of) WI

....Senior Unsecured Revenue Bonds, Affirmed A2

..Issuer: Northern States Power Company (Minnesota)

.... Issuer Rating, Affirmed A2

....Senior Unsecured Shelf, Affirmed (P)A2

....Senior Secured Shelf, Affirmed (P)Aa3

....Senior Secured First Mortgage Bonds, Affirmed Aa3

....Underlying Senior Secured First Mortgage Bonds, Affirmed Aa3

....Senior Unsecured Bank Credit Facility, Affirmed A2

....Senior Unsecured Commercial Paper, Affirmed P-1

..Issuer: Northern States Power Company (Wisconsin)

....Senior Unsecured Shelf, Affirmed (P)A2

....Senior Secured Shelf, Affirmed (P)Aa3

....Senior Secured First Mortgage Bonds, Affirmed Aa3

....Senior Unsecured Bank Credit Facility, Affirmed A2

....Senior Unsecured Commercial Paper, Affirmed P-1

..Issuer: Public Service Company of Colorado

.... Commercial Paper, Affirmed P-2

.... Issuer Rating, Affirmed A3

....Senior Secured Shelf, Affirmed (P)A1

....Senior Unsecured Shelf, Affirmed (P)A3

....Senior Secured First Mortgage Bonds, Affirmed A1

....Senior Unsecured Bank Credit Facility, Affirmed A3

..Issuer: Pueblo (County of) CO

....Senior Unsecured Revenue Bonds, Affirmed A3

....Underlying Senior Unsecured Revenue Bonds, Affirmed A3

..Issuer: Southwestern Public Service Company

....Senior Unsecured Commercial Paper, Affirmed P-2

..Issuer: Xcel Energy Inc.

.... Issuer Rating, Affirmed A3

....Senior Unsecured Shelf, Affirmed (P)A3

....Subordinate Shelf, Affirmed (P)Baa1

....Preferred Shelf, Affirmed (P)Baa2

....Junior Subordinate Shelf, Affirmed (P)Baa1

....Senior Unsecured Bank Credit Facility, Affirmed A3

....Senior Unsecured Commercial Paper, Affirmed P-2

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in June 2017. Please see the Rating Methodologies page on www.moodys.com for a copy of this methodology.

Xcel Energy Inc. (Xcel) is a holding company for vertically integrated utility subsidiaries, namely Northern States Power Company (Minnesota) (NSP-Minnesota, A2 stable), Public Service Company of Colorado (PSCo, A3 stable), Southwestern Public Service Company (SPS, Baa2 stable), and Northern States Power Company (Wisconsin) (NSP-Wisconsin, A2 stable). These subsidiaries serve 3.6 million electric and 2.0 million natural gas customers in eight states, but mostly in Minnesota, Colorado, New Mexico, Texas, and Wisconsin.

REGULATORY DISCLOSURES

For ratings issued on a program, series or category/class of debt, this announcement provides certain regulatory disclosures in relation to each rating of a subsequently issued bond or note of the same series or category/class of debt or pursuant to a program for which the ratings are derived exclusively from existing ratings in accordance with Moody's rating practices. For ratings issued on a support provider, this announcement provides certain regulatory disclosures in relation to the credit rating action on the support provider and in relation to each particular credit rating action for securities that derive their credit ratings from the support provider's credit rating. For provisional ratings, this announcement provides certain regulatory disclosures in relation to the provisional rating assigned, and in relation to a definitive rating that may be assigned subsequent to the final issuance of the debt, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive rating in a manner that would have affected the rating. For further information please see the ratings tab on the issuer/entity page for the respective issuer on www.moodys.com.

For any affected securities or rated entities receiving direct credit support from the primary entity(ies) of this credit rating action, and whose ratings may change as a result of this credit rating action, the associated regulatory disclosures will be those of the guarantor entity. Exceptions to this approach exist for the following disclosures, if applicable to jurisdiction: Ancillary Services, Disclosure to rated entity, Disclosure from rated entity.

Regulatory disclosures contained in this press release apply to the credit rating and, if applicable, the related rating outlook or rating review.

Please see www.moodys.com for any updates on changes to the lead rating analyst and to the Moody's legal entity that has issued the rating.

Please see the ratings tab on the issuer/entity page on www.moodys.com for additional regulatory disclosures for each credit rating.

Natividad Martel
Vice President - Senior Analyst
Infrastructure Finance Group
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 1 212 553 0376

Client Service: 1 212 553 1653

Michael G. Haggarty
Associate Managing Director
Infrastructure Finance Group
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

Releasing Office:
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 1 212 553 0376
Client Service: 1 212 553 1653

entity that is not a NRSRO and, consequently, the rated obligation will not qualify for certain types of treatment under U.S. laws. MJKK and MSFJ are credit rating agencies registered with the Japan Financial Services Agency and their registration numbers are FSA Commissioner (Ratings) No. 2 and 3 respectively.

MJKK or MSFJ (as applicable) hereby disclose that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by MJKK or MSFJ (as applicable) have, prior to assignment of any rating, agreed to pay to MJKK or MSFJ (as applicable) for appraisal and rating services rendered by it fees ranging from JPY200,000 to approximately JPY350,000,000.

MJKK and MSFJ also maintain policies and procedures to address Japanese regulatory requirements.

S&P Global
Ratings

RatingsDirect®

U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound

Primary Credit Analyst:
Todd A Shipman, CFA, Boston (1) 617-530-8241; todd.shipman@spglobal.com

Secondary Contact:
Kyle M Loughlin, New York (1) 212-438-7804; kyle.loughlin@spglobal.com

Table Of Contents

U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound

*(**Editor's Note:** This article is part of a series addressing the potential credit implications of U.S. tax reform on corporate, infrastructure, financial services, and U.S. public finance entities.)*

The recently enacted federal tax package will provide a modest economic uplift according to S&P Global economists (see "A Tax Package For The New Year: Its Impact On U.S. GDP Growth," Jan. 8, 2018), and it will be beneficial for the credit quality of most corporate issuers (see "U.S. Tax Reform: An Overall (But Uneven) Benefit For U.S. Corporate Credit Quality," Dec. 18, 2017). But what does it mean for the S&P Global Ratings' ratings on U.S. utilities and their holding companies?

The main features of the corporate tax package are a lower tax rate, more favorable treatment of earnings repatriated from overseas, a move from a worldwide tax system to a territory-based tax system, immediate expensing of capital investment, and limits on the deductibility of interest expense. For U.S. utilities and for most utility holding companies that have mainly domestic operations, foreign earnings repatriation and the taxation approach to those earnings are a non-issue. However, the tax package has important implications for utilities mostly because of rate regulation, but also since special provisions in the tax legislation for regulated utilities regarding interest deductibility and capex expensing distinguish them from most of corporate America.

Overview

- While most of corporate America is bullish about the new tax regime, we believe the effect on creditworthiness of regulated utilities and their holding companies could be negative.
- The effect will depend on the reaction of utility regulators and, ultimately, the utility companies after the regulators have acted.
- The lower statutory corporate tax rate will eventually benefit ratepayers, not utilities. The degree of benefit or burden to holding companies will depend on each company's tax position and will suffer from the benefit at the utility subsidiaries going to ratepayers.
- The accelerated deductibility of capital expenditures is not available to utilities, and the loss of that kind of stimulus is negative for cash flow.
- Few U.S. utility holding companies will be affected by foreign earnings or the deemed repatriation of previously untaxed foreign earnings.
- Limits on the deductibility of interest expense have little effect, as utilities are exempt and holding companies can participate in that exemption.

Credit Implications Vary For U.S. Utilities

The reality for U.S. utilities and utility holding companies is that they have historically used the tax code as a source of cash flow through the interactions of tax accounting, regulatory accounting, and as opportunities to defer cash taxes from economic stimulus provisions. The attractiveness of tax credits for specific types of investments for companies with such reliable earnings profiles has long been apparent. One reason we have relied more on after-tax credit metrics using funds from operations (FFO) as a base instead of pretax measures like EBITDA is that the former captured the true cash flow of a utility better than the latter. As we have noted in the past, utilities are susceptible to weakening FFO-based credit metrics in the absence of bonus depreciation or other economic stimulus built into the tax code.

We will address the three primary areas of tax reform for utilities in turn. Early analysis suggests that utility and holding company credit quality could be marginally and negatively affected by the new tax code, but for most issuers the magnitude will be mild enough to allow them, if so desired, to offset the effect enough to preserve ratings. Much will depend on the regulatory response. For companies skirting the edge of our financial risk profile requirements, the path to ratings stability will be trickier and steeper. Our approach as the impact of the corporate tax package unfolds will be measured:

- Taxes, as accounting and ratemaking matters, are extremely complex and will require some time for issuers and regulators to fully understand the implications, especially at the holding company level. As we observe the decisions made by each company and update our models, we will allow sufficient time for companies to react to the changes.
- To the extent tax reform has some one-time, up-front effect on earnings or prompts write-offs, we are likely to look past that and concentrate on the ongoing, forward-looking impact on credit metrics.
- Each company's tax situation is unique, as is the regulatory environments in which they operate. While we see a general effect of tax reform, ultimately the rating impact will be issuer-specific and will depend on the details of its tax positions at both the utility and holding company, the regulatory response to the new tax code, and how the company responds to those two things in its future financial policy.
- The impact will almost certainly differ between a holding company and its utilities. Holding companies do not directly share the same tax attributes as their utility subsidiaries and are the actual entity that pays taxes on a consolidated basis. Utilities are almost uniformly treated as stand-alone entities by regulators when calculating the revenues needed to cover the cost of service. Changes in things like corporate tax rates can therefore have decidedly different effects on the unregulated parent and the regulated subsidiary. Since our rating methodology is primarily focused on the entire group, the impact of tax reform on the holding companies is going to be the most impactful on the ratings within the group for most issuers. Although there may be no rating implications, we may revise the stand-alone credit profiles (SACP) of a holding company's utility subsidiaries that we do not consider insulated. And the ratings on utilities and other subsidiaries that differ from the parent due to insulation or a lesser group status could also be directly affected.

The Influence Of Key U.S. Tax Reform Provisions On U.S. Regulated Utilities and Holding Companies

Tax provision	Benefit or burden?	Primary relevance to utilities or holding companies?	Effect
Lower corporate tax rate	Burden	Both	For utilities, revenue requirement is reduced. The benefit of lower rate is passed onto ratepayers. Holding companies lose the cash flow from the difference between statutory rate and their effective tax rate.
Loss of accelerated deductibility of capital expenditures	Burden	Both	Utilities are exempted and therefore lose the opportunity to gain cash flow from tax-based stimulus. Effect on holding companies depends on mix of utility and non-utility operations.
Elimination of tax on foreign earnings and upon repatriation going forward	Benefit	Holding company	Limited to the few that have overseas investments.
Deemed tax on previously earned profits held overseas	Burden (limited to eight years)	Holding company	Limited to the few that have overseas investments.

The Influence Of Key U.S. Tax Reform Provisions On U.S. Regulated Utilities and Holding Companies (cont.)

Tax provision	Benefit or burden?	Primary relevance to utilities or holding companies?	Effect
Limit on interest deduction	Benefit	Both	Utilities not burdened (exempted). Holding companies are not burdened to the extent they can allocate a portion of their debt to utility operations, but the allocation method is unclear.

Source S&P Global Ratings.

Lower tax rates

The central feature of the corporate tax package is a lower tax rate. The current 35% statutory tax rate is now 21%, and that move has various ratemaking consequences for utilities. For most utilities, rates charged to customers reflect the statutory rate. Any unpaid deferred taxes over the years have been accrued for eventual return to ratepayers, and in the mean time are a low-cost source of capital in the mechanics of ratemaking. The new, lower statutory rate means (1) rates must be lowered to reflect the new rate, and (2) the excess deferred tax balance created by the difference in tax rates must be returned to ratepayers. The speed at which it is returned will be determined by the regulator with potentially significant negative cash flow effects. Normalization rules will restrict the regulators, but some of the deferred tax difference will not be protected by the transition rules and could be tapped earlier to reduce rates. Regulators will also be mindful of the higher future costs associated with rapid reversal of deferred taxes, as they have been a low-cost source of capital to the benefit of ratepayers that must be replaced with some combination of debt and equity if erased too quickly.

Both of those tasks will be handled by the regulator, with the timing and result affected by the utility's strategy and relationship with its regulators. That strategy, and the utility's ability to manage the process and outcome, are crucial factors in determining the impact on ratings coming out of tax reform. The challenge is that regulators think about and set rates primarily on earnings, not cash flow. To the extent that tax reform leads to lower cash flows, which we think will be the case in most instances, we will look for the utility to make a case for countervailing steps to offset some or all of the diminished cash flow. A stronger capital structure, using the extra revenues related to the difference between the 21% and 35% tax rates to support greater rate-base investment or rate recovery of other expenses such as unfunded pension obligations or nuclear decommissioning funds, or some combination of these could sustain or lessen the impact on credit metrics.

At the parent companies, which often have a mix of regulated and unregulated companies, the effect of lower tax rates could be more mixed and will depend greatly on each company's particular circumstance. They rarely pay anything close to the statutory rate due to careful tax planning. An important focus is on those holding companies that have significant non-utility operations. How to allocate parent debt between utility and non-utility operations is an unresolved issue (see next section), but overall many investments and activities on the non-utility side have been driven by tax considerations. A holding company's tax characteristics, including such things as net operating loss carryovers and unused tax credits, affect how much in actual taxes they're paying now. Lower tax rates will slow the realization of those and other tax benefits, and that could pressure credit metrics when combined with any negative cash-flow effects at the utility level.

Interest expense deductibility

The second big aspect of tax reform for utilities is interest deductibility. U.S. utilities and utility holding companies are typically more leveraged than their counterparts elsewhere in corporate ratings, so the loss or limit on deducting interest for tax purposes would have been more impactful for utilities. The new tax package offers a special carve-out that allows utilities to fully deduct all interest expense and holding companies to allocate a portion of the interest on parent debt associated with their utilities to qualify for a deduction as well. The manner of that allocation is still somewhat imprecise, and greater clarity is expected when the Treasury Department implements the legislation.

Loss of bonus depreciation or other tax stimulus

The preservation of most interest deductibility for the capital-intensive, more-levered utilities and utility holding companies came at a price. In exchange for this treatment, utilities forego the opportunity to participate in the stimulus feature of tax reform, full expensing of capital spending at least for the next five years. With the absence of any bonus depreciation provisions for utilities, a powerful generator of cash flow will now cease that, in combination with the lower tax rate, will have very real consequences for cash-based credit metrics. Utilities however have been modifying their capital spending plans over the past few years to factor in phasing out of bonus depreciation. We noted in a commentary many years ago (see "How Will Bonus Depreciation Affect The Credit Quality of U.S. Electric Utilities?" May 9, 2011) that the loss of bonus depreciation could result in two to three percentage-point reductions in a typical FFO-to-debt calculation. Now that the time of no tax stimulus in the tax code has come to pass, utilities will have to grapple with this lack of cash flow from tax timing differences. While the lower statutory rate would have diminished the power of this cash-flow source anyway, its absence will make the challenge more acute, especially for those issuers that are already edging toward ratings downgrade FFO-to-debt triggers.

Utilities' Response To The New Tax Laws May Help Preserve Credit Quality

The impact of tax reform on utilities is likely to be negative to varying degrees depending on a company's tax position going into 2018, how its regulators react, and how the company reacts in return. It is negative for credit quality because the combination of a lower tax rate and the loss of stimulus provisions related to bonus depreciation or full expensing of capital spending will create headwinds in operating cash-flow generation capabilities as customer rates are lowered in response to the new tax code. The impact could be sharpened or softened by regulators depending on how much they want to lower utility rates immediately instead of using some of the lower revenue requirement from tax reform to allow the utility to retain the cash for infrastructure investment or other expenses. Regulators must also recognize that tax reform is a strain on utility credit quality, and we expect companies to request stronger capital structures and other means to offset some of the negative impact.

Finally, if the regulatory response does not adequately compensate for the lower cash flows, we will look to the issuers, especially at the holding company level, to take steps to protect credit metrics if necessary. Some deterioration in the ability to deduct interest expense could occur at the parent, making debt there relatively more expensive. More equity may make sense and be necessary to protect ratings if financial metrics are already under pressure and regulators are aggressive in lowering customer rates. It will probably take the remainder of this year to fully assess the financial impact on each issuer from the change in tax liabilities, the regulatory response, and the company's ultimate response.

We have already witnessed differing responses. We revised our outlook to negative on PNM Resources Inc. and its subsidiaries on Jan. 16 after a Public Service Co. of New Mexico rate case decision incorporated tax savings with no offsetting measures taken to alleviate the weaker cash flows. It remains to be seen whether PNM will eventually do so, especially as it is facing other regulatory headwinds. On the other hand, FirstEnergy Corp. issued $1.62 billion of mandatory convertible stock and $850 million of common equity on Jan. 22 and explicitly referenced the need to support its credit metrics in the face of the new tax code in announcing the move. That is exactly the kind of proactive financial management that we will be looking for to fortify credit quality and promote ratings stability.

Related Criteria And Research

Related Research

- FirstEnergy Corp.'s Convertible Preferred Stock Issuance Rated 'BB'; Other Ratings Affirmed, Jan. 22, 2018
- PNM Resources Inc. And Subs Outlooks Revised To Negative On New Mexico Regulatory Order, Effects Of New U.S. Tax Code, Jan. 16, 2018
- A Tax Package For The New Year: Its Impact On U.S. GDP Growth, Jan. 8, 2018
- U.S. Tax Reform: An Overall (But Uneven) Benefit For U.S. Corporate Credit Quality, Dec. 18, 2017
- How Will Bonus Depreciation Affect The Credit Quality of U.S. Electric Utilities? May 9, 2011

S&P Global
Ratings

RatingsDirect®

Research Update:

American Water Works Co. Inc. And Subsidiaries 'A' Ratings Affirmed; Outlooks Remain Stable

Primary Credit Analyst:
Safina Ali, CFA, New York (1) 212-438-1877; safina.ali@spglobal.com

Secondary Contact:
Obioma Ugboaja, New York + 1 (212) 438 7406; obioma.ugboaja@spglobal.com

Table Of Contents

Research Update:

American Water Works Co. Inc. And Subsidiaries 'A' Ratings Affirmed; Outlooks Remain Stable

Overview

- We expect American Water Works Co. Inc. (AWK) to strategically maintain its regulated water and wastewater operations between 90%-95% of the company's consolidated EBITDA.
- In our view, AWK's business risk now reflects the higher half of the range of its business risk profile category when compared to peers incorporating the company's strategic commitment, its large and diversified customer base, and effective management of regulatory risk. This will offset marginally weaker financial measures.
- We are affirming our 'A' issuer credit rating on AWK and subsidiaries Pennsylvania-American Water Co. (PAW) and New Jersey-American Water Co. (NJAW). The outlook on all entities remains stable.
- The stable outlook on AWK and subsidiaries reflects our expectation that the company will continue to focus its strategic growth on its regulated water distribution operations, maintaining the regulated businesses between 90%-95% of EBITDA. In addition, we expect the company will continue to manage regulatory risk effectively, maintaining marginally weaker financial measures consistent with the lower end of its financial risk profile category.

Rating Action

On June 11, 2018, S&P Global Ratings affirmed its 'A' issuer credit ratings on American Water Works Co. Inc. (AWK) and subsidiaries Pennsylvania–American Water Co. (PAW) and New Jersey-American Water Co. (NJAW). The outlooks are stable.

We also affirmed the 'A' unsecured debt rating on American Water Capital Corp. (AWCC), 'A-1' short-term rating at AWCC and AWK, and A+' ratings on PAW's and NJAW's secured debt.

Rationale

The ratings affirmation reflects our expectations that the company's strong commitment to maintain its low-risk, regulated operations between 90%-95% of AWK's consolidated EBITDA offsets marginally weaker financial measures.

We assess AWK's business risk profile at the higher half of the range for its business risk profile category, compared to peers. This reflects the company's monopolistic and lower-risk, regulated water distribution and wastewater business providing an essential service in regulatory jurisdictions that we generally view as supportive of credit quality. AWK's operations benefits from constructive mechanisms such as the distribution system investment charge (DSIC) and infrastructure replacement surcharges in a number of its jurisdictions, which allow for the recovery of high capital spending outside of a traditional rate-case proceeding and reduces regulatory lag. In addition, some of the key jurisdictions benefit from forward-looking test years and revenue stabilization mechanisms, which help the company to earn close to its allowed return on equity (ROE) year-over-year. The company's geographic diversity and solid operating efficiency further supports its business risk profile.

AWK, largest in size and diversity among all water companies in the U.S., serves approximately 3.4 million water and wastewater customers across 16 states, out of which New Jersey, Pennsylvania, and Illinois are largest by customer base and revenue contribution. New Jersey, Pennsylvania, and Illinois account for about 25%, 22%, and 10% of the company's revenues and customer base, respectively. AWK's water and wastewater operations are reliable, safe, and consistently comply with all necessary safety standards. The businesses also focus strongly on controlling expenses leading to O&M efficiency ratios in line with industry peers.

AWK's nonregulated businesses largely consist of its Homeowner Services Group and its Military Services Group. All other divisions (Contract Operations and Keystone Clearwater Solutions) contribute minimally to the nonregulated operations.

Over time, the company has streamlined its nonregulated operations and improved its competitiveness. In general, AWK's nonregulated businesses are diversified, affiliated to regulated service jurisdictions, have modest capital spending requirements, and are stable cash flow contributors. The Homeowner Services business (the largest among the nonregulated operations) runs a home warranty business offering water and sewer protection contracts to homeowners. Although the business is subject to competition, there is low customer turnover largely because the charges are part of utility water bills for a significant number of customers, which has helped retain customers. The company recently acquired Pivotal Home Solutions (Pivotal) for $363.7 million. The acquisition of Pivotal, in addition to increasing the number of contracts for Homeowner Services Group, also diversifies company's exposure by introducing new type of contracts (gas line, plumbing, heating, ventilation, and air conditioning, etc.). The Military Services business, the second-largest component of nonregulated operations, shares several utility-like risk characteristics. The business has similar operations profile featuring long-term contract lengths (50 years) with U.S. military bases with contract prices that cover operation and maintenance (O&M) costs, capital program and system expansion costs. These factors, collectively, somewhat reduce our perception of risk associated with AWK's nonregulated businesses. On a forward-looking basis, we expect that the EBITDA contribution from nonregulated operations will not deviate materially from its current contribution (about 8% of consolidated AWK's EBITDA).

We assess AWK's financial risk profile using our most relaxed financial ratio benchmarks compared to those used for a typical corporate issuer, reflecting the company's low-risk, regulated water distribution operations and its overall effective management of regulatory risk. Under our base-case scenario, we expect AWK's consolidated financial measures to weaken over the next couple of years primarily due to the tax reform, loss of bonus depreciation, and higher capital spending. Specifically for 2018, our base case assumes single-digit EBITDA growth, $1.9 billion of capital spending, $320 million of dividends, and consistent regulatory recoveries through rate cases and use of cash smoothing mechanisms. We expect funds from operations (FFO) to total debt to be at the lower end of the range for the company's current financial risk profile category, at about 13%-14% over next three years. Previously, FFO to debt was about 17%. The weaker financial measures are indicative of minimal cushion at its current rating level and is consistent with our assessment of the comparable rating analysis modifier as negative.

Liquidity

AWK has adequate liquidity and can more than cover its needs for the next 12 months, even if EBITDA declines by 10%. We expect the company's liquidity sources over the next 12 months will exceed uses by more than 1.1x. AWK's liquidity benefits from the company's ability to absorb a high-impact, low-probability event with limited need for refinancing, well-established relationships with banks, a satisfactory standing in the credit markets, and manageable debt maturities over the next few years.

Principal liquidity sources:

- FFO of $1.3 billion;
- Committed equity issuance proceeds of about $183.3 million; and;
- Assumed credit facility availability of about $2.2 billion.

Principal liquidity uses:

- Debt maturities, including outstanding short-term debt of about $1.2 billion;
- Maintenance capital spending of about $1 billion;
- Cash dividends of about $320 million; and
- Committed acquisitions of about $363 million.

Other Credit Considerations

We assess the comparative rating analysis modifier as negative, reflecting financial measures that we expect to weaken and remain at the lower end of the company's current financial risk profile category.

Group Influence

We assess AWK as the parent of a group that includes New Jersey American Water Co., Pennsylvania American Water Co., and American Water Capital Corp. (AWCC). As a result, AWK's stand-alone credit profile of 'a' becomes the group credit profile, leading to our 'A' issuer credit rating on AWK.

Outlook

The stable outlook on AWK and subsidiaries reflects our expectation that the company will continue to focus its strategic growth on its regulated water distribution operations, maintaining the regulated businesses between 90%-95% of consolidated EBITDA. In addition, we expect the company will continue to manage regulatory risk effectively, maintaining financial measures at the lower end of its financial risk profile category. Under our base-case scenario forecast, we expect annual adjusted FFO to debt averaging around 13%-14%.

Downside scenario

We could lower the ratings on AWK and subsidiaries if the nonregulated operations increased such that they consistently contribute disproportionally to the consolidated EBITDA or the nonregulated operations become riskier than our current assessment. In addition, deteriorating management of regulatory risk or financial measures lower than our base-case expectations, specifically FFO to debt consistently below 13% could also lead to lower ratings.

Upside scenario

We could raise the ratings if adjusted FFO to debt consistently remains over 16%. This could occur if the company consistently managed its regulatory risk and achieved higher-than-expected rate-case outcomes, along with continued prudently managed expenses and use of lower debt and more equity to fund capital expenditures and acquisitions.

Ratings Score Snapshot

Corporate Credit Rating: A/Stable/A-1

Business risk: Excellent
- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Intermediate

- Cash flow/Leverage: Intermediate

Anchor: a+

Modifiers
- Diversification/Portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Negative (-1 notch)

Stand-alone credit profile: a
- Group credit profile: a

Issue Ratings--Subordination Risk Analysis

We base our 'A-1' short-term rating on AWCC and AWK on the companies' respective issuer credit rating.

Capital structure

AWK's capital structure consists of about $6.8 billion of debt, out of which about $5.4 billion is issued at AWCC and about $1.3 billion is issued at operating subsidiaries.

Analytical conclusions

The senior unsecured debt at AWK's finance entity, AWCC, is rated the same as the issuer credit rating because subsidiary debt does not exceed 50% of AWK's consolidated debt after which point AWCC's debt could be considered structurally subordinated.

Related Criteria

- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings , April 7, 2017
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013

- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria - Corporates - Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Criteria - Insurance - General: Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008

Ratings List

Ratings Affirmed

American Water Works Co. Inc.	
American Water Capital Corp.	
Corporate Credit Rating	A/Stable/A-1
New Jersey-American Water Co.	
Pennsylvania-American Water Co.	
Corporate Credit Rating	A/Stable/--
American Water Capital Corp.	
Senior Unsecured	A
Commercial Paper	A-1

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
16 February 2018

Update

Rate this Research

RATINGS

American Water Works Company, Inc.

Domicile	Voorhees, New Jersey, United States
Long Term Rating	A3
Type	LT Issuer Rating - Dom Curr
Outlook	Negative

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

Contacts

Ryan Wobbrock +1.212.553.7104
VP-Senior Analyst
ryan.wobbrock@moodys.com

Dexter East +1.212.553.3260
Associate Analyst
dexter.east@moodys.com

Jim Hempstead +1.212.553.4318
MD-Utilities
james.hempstead@moodys.com

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

American Water Works Company, Inc.

Update following negative outlook

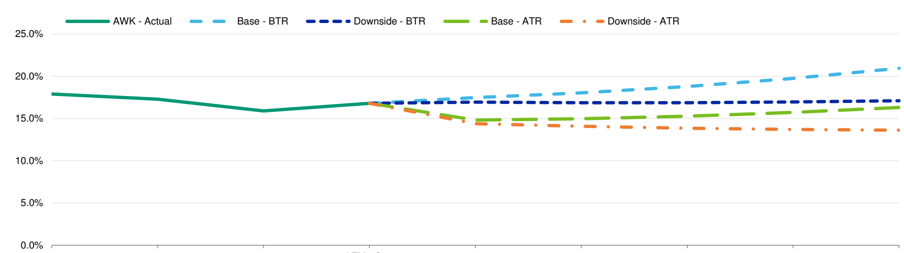
Summary

American Water Work Company, Inc.'s (American Water, or AWK, A3 negative) credit profile is supported by 1) its market position as the largest US investor-owned water utility holding company, 2) strong regulatory and operational diversity across 16 states, 3) improving regulatory support as more states adopt cost recovery trackers.

The company's credit is constrained by 1) increasing leverage due to financial policies that target over $8.0 billion of capex, dividend growth approaching 10% and no planned equity issuances over the next five years, 2) a new tax law that will result in cash flow leakage and 3) subordinated holding company debt that is about 23% of total consolidated debt.

In the exhibit below, we show four Moody's projection scenarios for American Water's funds from operations (FFO) to net debt ratio. The analysis compares our view of cash flow production "before tax reform" (BTR) and "after tax reform" (ATR), using assumptions based upon our interpretation of American Water's five year guidance drivers, as a base case, and a downside scenario that cuts earnings growth in half. While we do not currently view AWK's credit profile according to the downside scenario, it is a sensitivity analysis that attempts to capture the possibility for unforeseen developments, such as lower growth, regulatory challenges, higher than expected outflows from tax reform, underperformance of unregulated operations, etc. Other assumptions behind these scenarios are noted in the footnote below.

Exhibit 1
Our FFO to net debt expectations, for AWK, are now lower as a result of tax reform
FFO to net debt



All scenarios include: 10% dividend growth; 100% debt financing of negative free cash flow; 2% cash tax rate.
The "Base" scenario and "Downside" scenario reflect consolidated net income CAGRs of 9.0% and 4.5%, respectively. The CAGRs are based off of LTM 3Q17 figures.
BTR assumed a 40% effective tax rate 2018-2022, ATR assumed a 25% effective tax rate 2018-2022.
Source: American Water Works, Inc. SEC filings, Moody's Investors Service projection assumptions

Credit strengths

» Diversity of holdings with 16 regulated water utilities

» Supportive regulatory environments with timely recovery mechanisms

» Support agreement at AWCC not a "guarantee" but provides sufficient credit substitution

Credit challenges

» Financial metrics will weaken due to increasing leverage and cash flow leakage

» Financial policies evidence an increased risk tolerance

» High capital expenditures and more sizeable regulated acquisitions will continue

Rating outlook

American Water's negative outlook reflects financial metrics that had been expected to decline due to debt-funded growth and now a trajectory that will decline further due to Federal tax reform. We expect FFO to net debt metrics to decline to around 15% over the next 12-18 months.

American Water's credit profile could be maintained if FFO to net debt and RCF to net debt were to stabilize around 16% and 11%, respectively, and without an increase in parent debt levels (currently at approaching 25% of consolidated debt).

Factors that could lead to an upgrade

» FFO to net debt metrics at 20%, on a sustainable basis, while maintaining its current business risk profile

» RCF to debt around 15%

» Improved credit profiles of a majority of its operating subsidiaries

Factors that could lead to a downgrade

» Less supportive regulatory provisions (especially in Pennsylvania or New Jersey)

» Increased financial risk, such as the stand-alone AWCC debt increasing toward 25% of consolidated debt or consolidated FFO to debt around 15% for a sustained period.

» Operational concerns such as supply or asset failure

Key indicators

Exhibit 2
American Water Works indicators

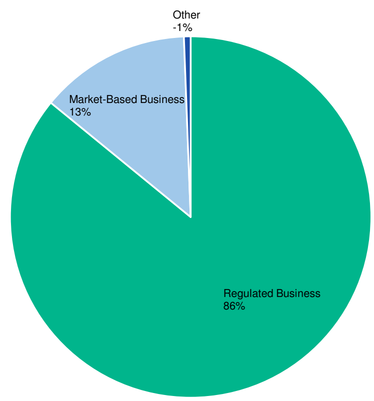
	Dec-13	Dec-14	Dec-15	Dec-16	LTM Sep-17
FFO Interest Coverage	4.2x	4.6x	4.6x	4.5x	4.6x
Debt / Capitalisation	48.1%	47.7%	48.6%	49.6%	48.8%
FFO / Net Debt	17.7%	18.0%	17.4%	16.0%	17.0%
RCF / Net Debt	15.2%	14.6%	13.9%	12.6%	13.4%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

Headquartered in Voorhees, New Jersey, American Water Works Company, Inc. is the largest investor-owned provider of water, wastewater and related services in North America, with operations serving an estimated 15 million people across 46 states and the District of Columbia in the US and a Canadian province. The company's regulated operations span across 16 states and accounts for just under 90% of consolidated operating revenue. The exhibit below shows the relative contribution and growth of revenue from its core utility segment and unregulated operations.

Exhibit 3
The vast majority of American Water's operating revenue is derived from low-risk regulated utilities



Source: American Water Works Company, Inc. 2016 10K

American Water is a holding company and does not have any direct debt obligations; rather, it primarily issues debt through its non-operating financing subsidiary American Water Capital Corp, which has a support agreement with American Water.

Detailed credit considerations

Financial metric decline will continue due to debt-funded growth and increasing dividend

American Water's debt is expected to increase due to the financial policies in its 5-year plan. Through 2022, the company expects to spend $8.0-$8.6 billion in capex, provide dividend growth approaching 10% and issue no additional equity. We view these policies as management evidencing a higher financial risk tolerance, and we project funds from operations (FFO) to net debt ratios will continue to drop from the 18% posted in 2014 (17% through LTM 3Q17) to a sustainable 16%, as a result.

With over $8.0 billion in capex, we estimate that American Water's reported debt will be around $10 billion by 2022 and will continue to outpace the growth of FFO. Similarly, we expect that a dividend growth rate approaching 10% will also roughly double the pace of FFO growth that we expect over this time.

Cash leakage from tax reform will further pressure financial ratios

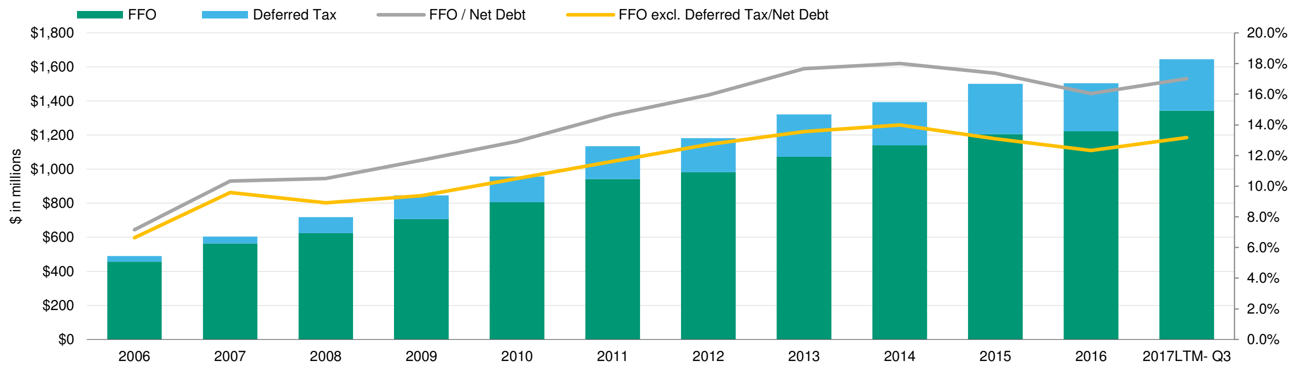
We see tax reform as having a negative credit impact due to cash leakage resulting from a lower tax rate, which will reduce deferred tax contribution to cash flow, and customer refunds from excess deferred tax liabilities. We estimate that the deferred tax cash flow benefit will be cut in half as a result of the Federal tax rate move to 21% and that the excess liabilities will be returned to customers over time.

For American Water, we estimate that losing around $150 million of cash flow to deferred taxes, will further pressure FFO to debt to around 15% over the next several years. 15% is a level that we have highlighted as potentially impacting the credit profile of American Water. In the two exhibits below

Over the past 10 years, American Water, like most of the utility sector, has benefitted from various tax offsets that have kept cash tax payments low. Federal policies, like bonus depreciation, has resulted in a significant amount of temporary tax savings, resulting in higher increased deferred tax balances.

The impacts from bonus depreciation and other tax policies have provided significant boosts to cash flow, as seen in the exhibit below. For American Water, the deferred tax contribution to FFO has grown from a negligible amount in 2006, to around 23% through LTM 3Q17.

Exhibit 4
Deferred Tax has become a large boost to American Water's cash flow in recent years.

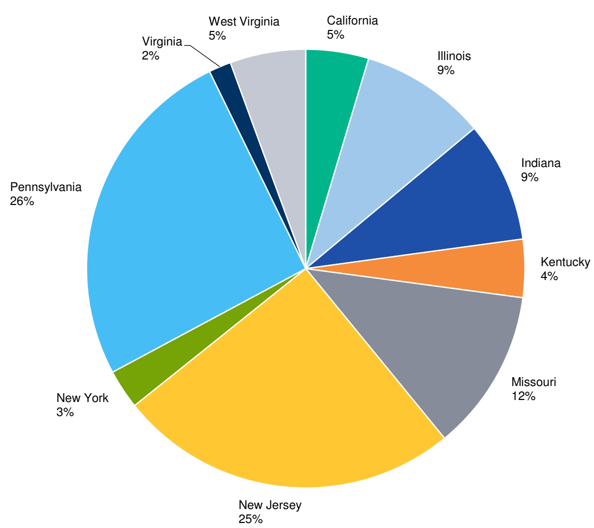


Source: American Water Works, Inc. financial statements, Moody's Financial Metrics

Broad utility diversity and improving regulatory support

AWK is a holding company with around 87% of its revenue produced by low-risk water utility companies, spanning 16 states. AWK's credit strength reflects the size, scale of this diversity, along with the monopoly service characteristics of water utilities that offer stable and predictable cost recovery and cash flow coverage of debt and interest.

Exhibit 5
American Water has a very diverse asset base, with utility operations in 16 different states.



Source: American Water Works Company, Inc. 2016 10K

Over the past several years, we have observed improving regulatory trends in the US, which include the increased prevalence of automatic cost recovery provisions such as revenue decoupling and infrastructure replacement mechanisms, as well as the willingness to adopt more forward-looking test year data in rate making. This trend has helped to expedite cost recovery (and reduce regulatory lag) and improve fixed cost recovery across AWK's various utility service territories.

One of the more significant cost recovery features is the ability to make discrete rate filings in order to recover the costs of replacing aging infrastructure. Often called distribution system improvement charges (DSIC), these mechanisms provide AWK timely recovery of capital expenditures on an ongoing basis. Another important cost recovery feature is the use of declining usage adjustments (or "decoupling mechanisms" that target a specific gross profit needed to cover fixed operating costs, regardless of the volume of water sold) which are available in the rates of nine state, including AWK's six largest jurisdictions.

The exhibit below provides detail around some of the more important cost recovery features that are allowed in states that American Water serves.

Exhibit 6

Credit supportive cost recovery mechanisms exist in many of the states that American Water serves.

Cost Recovery Feature	States In-Use
Future Test Year	CA, HI, IL, IN, KY, NY, PA, TN, VA
Inrastructure Replacement	IL, IN, MO, NJ, NY, PA, TN, WV
Plant Recovery Mechanisms	CA, IL, KY, NY, PA, TN, VA
Decoupling	CA, IL, NY

Recovery feature names are per Moody's description
Source: American Water 10K, Moody's

The broad improvement in regulatory cost recovery, across all jurisdictions, has allowed AWK and AWCC ratings to overcome the limited structural subordination that exists at its operating companies, and has resulted in a ratings level on-par with its largest subsidiaries: New Jersey American Water (NJ-AWC A3 stable) and Pennsylvania American Water (PAWC A3 stable).

Most unregulated businesses are utility-like and relatively small

Non-regulated operations are generally higher risk versus utility operations, since they depend on market prices for cost recovery and are subject to greater competition; however, AWK's contracted services (e.g., O&M agreements with municipalities) or homeowner services activities are within the core competencies of water system operations. In fact, once contracts are obtained for military base operations, they offer a stable and predictable source of revenue and cash flow for 50 years. Therefore, we do not view these business lines as negatively impacting the overall credit of AWK. Furthermore, these segments have not, to date, required a significant amount of capital or reliance on credit support from the parent.

Similarly, the company's growing homeowner services and a contract services groups operate and maintains water and wastewater facilities for residential, municipal and corporate customers. These contracts are of shorter duration, but are not viewed as high risk.

On the other hand, we view the company's ownership of Keystone Clearwater Solutions (Keystone; unrated - a provider of water services to support hydraulic fractionation of shale gas plays) as higher risk, since the revenue is more volume based, short-term and derived from a speculative credit grade Exploration and Production (E&P) industry that bases decisions on commodity prices. Furthermore, we think there is reputational risks that AWK takes on, as they intermingle operations with E&P companies that carry a higher level of environmental exposure.

Despite these negatives, Keystone is very small compared to AWK and has little bearing on the company's credit profile. Should more of AWK's unregulated investments carry this type of risk profile, or grow to be a meaningful portion of the business (i.e. above 15% of operations), AWK's credit would be negatively affected.

Liquidity analysis

American Water's liquidity is managed through its financing subsidiary, AWCC, which extended its $1.75 billion credit facility to expire in June 2020. This credit facility provides support to the company's $1.6 billion commercial paper (CP) program (P-2). Although there are no restrictions for revolver borrowings, related to CP outstanding, we expect the company to leave ample cushion under the revolver to effectively backstop any CP borrowings. The facility has same-day drawing availability and no ongoing material adverse change clause. The lone financial covenant is maximum debt to capitalization ratio of 70%. As of 30 September 2017, the company's ratio was in compliance at 58%.

At 30 September 2017, $86 million in letters of credit outstanding and $103 million of commercial paper outstanding, leaving around $1.56 billion available under the facility.

In August 2017, AWCC issued $600 million 2.95% Senior Notes due 2027 and $750 million of 3.75% Senior Notes due 2047. The use of proceeds is to (1) repay $524 million of AWCC notes upon maturity in October 2017; (2) prepay $138 million of 5.62% AWCC debt due December 2018 and $181 million aggregate principal of 5.77% AWCC notes due December 2021; and (3) repay AWCC's CP obligations and for general corporate purposes.

The next material long-term debt maturities for American Water include AWCC obligations of $110 million due in May of 2018 and $191 million due in December of 2018.

Structural considerations

Following the aforementioned debt issuance in August 2017, AWK has approximately $7.4 billion of consolidated reported long-term debt, roughly $6.0 billion of which was issued at AWCC. The majority of AWCC's debt (approximately $4.0 billion) has been advanced via inter-company notes to various regulated utility subsidiaries and is part of their respective regulated capital structures. We estimate that about $2.0 billion of AWCC obligations are strictly holding company debt, which we view to be subordinate to the debt which supports the operating companies, since it only has utility dividend distributions as cash sources available for its debt service. Negative credit implications would ensue for AWCC and American Water if the holding company debt to consolidated debt ratio (currently at about 23%) grows to around 25%.

AWCC, a Delaware corporation, is the wholly-owned finance subsidiary of American Water, whose purpose is to streamline the financing function, create cash management efficiencies, and often obtain lower the cost of capital for American Water's regulated water utility subsidiaries. The source of upstream debt service funding comes from the regulated utility operations, which make cash principal and interest payments directly to AWCC. We expect any additional up-streamed cash flows, in the form of dividends to AWK, will be limited to maintain the respective regulatory allowed equity capitalization for each utility (generally around 50%).

AWCC's A3 senior unsecured rating is equalized with its parent, American Water, which provides credit enhancement through a support agreement between American Water and AWCC. The features contained in the support agreement, that support Moody's view of credit substitution include: 1) no termination of the support agreement until all debt shall have been irrevocably paid in full, without all lenders' (including debt trustees) consent, 2) American Water has agreed to make timely payment of interest, principal or premium on any debt issued by AWCC, if AWCC is unable to make such payments 3) the aforementioned payment is in the form of cash or liquid assets and not merely collection, 4) American Water waives any claims related to a failure or delay by AWCC in enforcing its rights under the support agreement, 5) the support agreement is binding on any successors of American Water, 6) the lender may proceed directly against American Water to obtain payment of defaulted interest, principle or premium, and 7) any changes to the support agreement that adversely affect lenders must be approved by such parties. Furthermore, American Water has committed to own, during the term of the support agreement, all of the voting stock of AWCC and to ensure that a positive tangible net worth at AWCC will be maintained at all times and the support agreement is governed by the laws of the state of New York, which we view to be hospitable to the enforcement of guarantees.

Although the support agreement has many attributes of what a guarantee provides, we note that it is not specifically or legally considered a guarantee. Also, debt at AWCC does not benefit from any explicit upstream guarantees from the regulated utility subsidiaries nor does the debt obligations of the subsidiaries benefit from any explicit downstream guarantee from American Water or AWCC. Nevertheless, given the agreement's stated protections, and that a significant amount of AWCC's debt has been incurred to finance rate base, we effectively view the support agreement structure as being similar to a guarantee for rating purposes and have made no notching differentiation between the two entities.

Rating methodology and scorecard factors

Exhibit 7

Rating Factors				
American Water Works Company, Inc.				
Regulated Water Utilities Industry Grid [1][2]	Current LTM 9/30/2017		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Business Profile(50%)	**Measure**	**Score**	**Measure**	**Score**
a) Stability and Predictability of Regulatory Environment	Aa	Aa	Aa	Aa
b) Asset Ownership Model	Aa	Aa	Aa	Aa
c) Cost and Investment Recovery (Sufficiency & Timeliness)	Baa	Baa	Baa	Baa
d) Revenue Risk	Baa	Baa	Baa	Baa
e) Scale and Complexity of Capital Programme & Asset Condition Risk	Baa	Baa	Baa	Baa
Factor 2 : Financial Policy (10%)				
a) Financial Policy	Ba	Ba	Ba	Ba
Factor 3 : Leverage and Coverage (40%)				
a) FFO Interest Coverage (3 Year Avg)	4.6x	A	4x - 5x	A
b) Debt / Capitalisation (3 Year Avg)	48.2%	A	46% - 56%	A
c) FFO / Net Debt (3 Year Avg)	17.2%	A	14% - 17%	A
d) RCF / Net Debt (3 Year Avg)	13.6%	A	10% - 14%	A
Rating:				
Indicated Rating from Grid Factors 1-3		A3		A3
Rating Lift	**0**	**0**		**0**
a) Indicated Rating from Grid		A3		A3
b) Actual Rating Assigned		A3		A3

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2]As of 9/30/2017(L)
[3]This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Appendix

Exhibit 8
Cash flow ad credit measures[1]

	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	LTM 09/30/2017
FFO	**$983**	**$1,072**	**$1,140**	**$1,205**	**$1,222**	**$1,343**
- Div	$213	$149	$216	$239	$261	$282
RCF	**$769**	**$923**	**$924**	**$966**	**$961**	**$1,061**
FFO	$983	$1,072	$1,140	$1,205	$1,222	$1,343
+/- ΔWC	$39	-$137	$3	-$13	$9	-$77
+/- Other	$23	$12	-$20	$4	$70	$76
CFO	**$1,044**	**$947**	**$1,123**	**$1,196**	**$1,301**	**$1,342**
- Div	$213	$149	$216	$239	$261	$282
- Capex	$952	$999	$974	$1,177	$1,332	$1,368
FCF	**-$121**	**-$202**	**-$67**	**-$220**	**-$292**	**-$308**
Debt / EBITDA	**4.4x**	**4.3x**	**4.4x**	**4.5x**	**4.8x**	**4.5x**
EBITDA / Interest	**4.0x**	**4.2x**	**4.5x**	**4.7x**	**4.5x**	**4.7x**
FFO / Net Debt	**15.9%**	**17.7%**	**18.0%**	**17.4%**	**16.0%**	**17.0%**
RCF / Net Debt	**12.5%**	**15.2%**	**14.6%**	**13.9%**	**12.6%**	**13.4%**

[1]All figures & ratios calculated using Moody's estimates & standard adjustments.
Source: Moody's Financial Metrics

Exhibit 9

Peer comparison table[1]

	American Water Works Company, Inc. A3 Negative			Severn Trent Plc Baa1 Negative			United Utilities PLC Baa1 Stable		
(in US millions)	FYE Dec-15	FYE Dec-16	LTM Sep-17	FYE Mar-15	FYE Mar-16	FYE Mar-17	FYE Mar-15	FYE Mar-16	FYE Mar-17
Revenue	$3,159	$3,302	$3,338	$2,905	$2,644	$2,378	$2,774	$2,608	$2,228
Funds from Operations	$1,205	$1,222	$1,343	$1,150	$1,055	$995	$1,514	$1,383	$1,229
Net Debt	$6,940	$7,615	$7,894	$7,841	$7,461	$7,287	$8,648	$8,780	$8,046
(FFO + Interest Expense) / Interest Expense	4.6x	4.5x	4.6x	3.7x	4.1x	4.3x	5.1x	5.5x	4.9x
FFO / Net Debt	17.4%	16.0%	17.0%	13.5%	13.5%	13.1%	16.1%	15.0%	14.6%
RCF / Net Debt	13.9%	12.6%	13.4%	9.7%	9.7%	9.8%	11.8%	10.8%	10.5%
FCF / Debt	-3.1%	-3.8%	-3.9%	-1.0%	-0.5%	-0.4%	-4.2%	-3.7%	-1.6%

[1]All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

Ratings

Exhibit 10

Category	Moody's Rating
AMERICAN WATER WORKS COMPANY, INC.	
Outlook	Negative
Issuer Rating	A3
AMERICAN WATER CAPITAL CORP.	
Outlook	Negative
Issuer Rating	A3
Senior Unsecured	A3
Commercial Paper	P-2
NEW JERSEY-AMERICAN WATER COMPANY, INC.	
Outlook	Stable
Issuer Rating	A3
PENNSYLVANIA-AMERICAN WATER COMPANY	
Outlook	Stable
Issuer Rating	A3
Bkd Senior Secured	A1

Source: Moody's Investors Service

REPORT NUMBER 1109572

MOODY'S
INVESTORS SERVICE

Markets

Utility M&A Is So Hot Not Even Berkshire's Billions Won a Bid

By Mark Chediak, Ryan Collins, and Jim Polson
January 3, 2018, 6:01 AM EST
Updated on January 3, 2018, 3:57 PM EST

- Last year's $68 billion transaction tally was most in decade
- Dominion takes spree into 2018 with $7.9 billion Scana buy

Why Scana Agreed to Be Acquired by Dominion

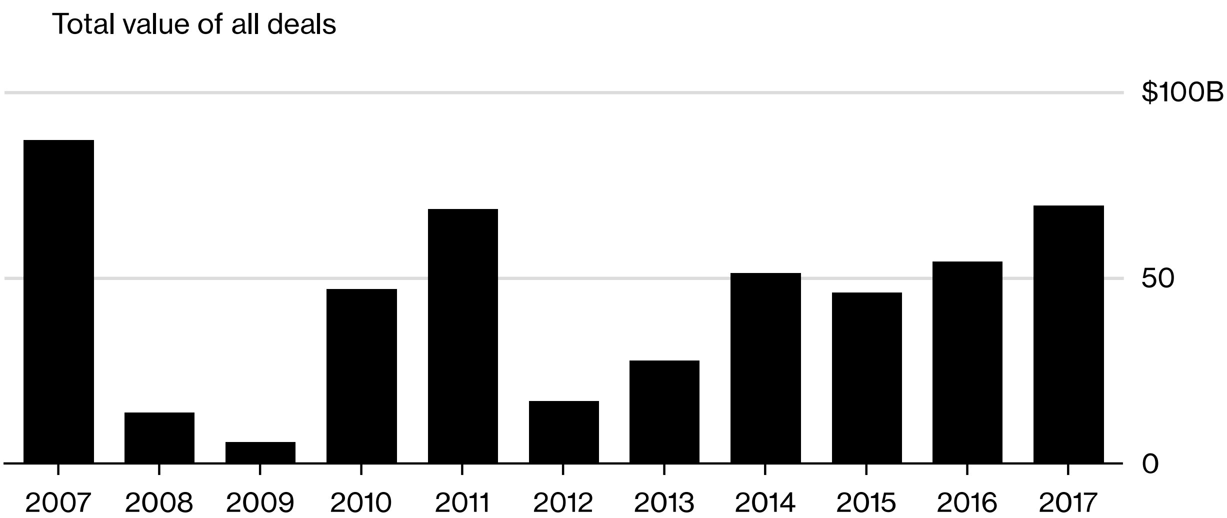
There are few things that better illustrate the banner year 2017 was for deals among North American power companies than this: Even billionaire Warren Buffett's Berkshire Hathaway Inc. wasn't able to come away with a winning bid.

The industry saw $68.2 billion of acquisitions in 2017, the most in a decade, according to data compiled by Bloomberg. With electricity prices low and profit margins tight, the buying spree is continuing into the new year with Dominion Energy Inc. announcing on Wednesday it will buy Scana Corp., a utility battered by a failed nuclear project, for $7.9 billion in a stock-for-stock deal.

"It's a seller's market," said William Lamb, a partner at New York law firm Baker Botts LLP, before the Dominion deal was announced. "There just aren't that many companies out there to buy, so when things come on to market, buyers tend to be willing to reach."

Utility Deals Surge

Buyers seeking growth amid flat energy demand



Source: Data compiled by Bloomberg

The Scana transaction is valued at about $14.6 billion including the assumption of debt, according to a statement Wednesday. It follows a 47 percent share decline for Scana over the past year.

Last year's top prize was Oncor Electric Delivery Co., the biggest transmission-line operator in Texas. It had drawn at least four suitors in recent years, including the Berkshire energy unit run by Greg Abel, who is often mentioned as a possible successor to the 87-year-old Buffett. Abel made an all-cash bid valued at $18.2 billion -- including the assumption of Oncor debt. But Sempra Energy offered $18.8 billion, and Abel declined to top it.

The intense pursuit of Oncor shows how determined companies are to acquire rivals and expand. One reason is that regulated utilities are under increasing pressure from shareholders to cut costs by consolidating, especially with interest rates still low enough to make borrowing money attractive. The industry has been hit hard by stagnant or declining electricity sales, and many face rising costs to replace aging infrastructure.

At the same time, independent power producers are also struggling. They run plants that sell electricity into competitive wholesale markets, where electricity prices have collapsed. That's mostly because of a flood of cheap natural gas being used as a fuel by more generators. Plus, about 17 percent of U.S. power was expected to come from renewables like solar and wind in 2017, twice the market share of a decade earlier, government forecasts show.

For an outlook on deals in 2018, click here.

"There is a continued belief in economies of scale," said Roger Wood, managing director at Moelis & Co., who has spent three decades as an investment banker and has advised on some major power deals. "If you are larger, you could be more relevant to investors, and better able to deliver good service to your customers."

An expanded footprint was the goal for San Diego-based Sempra, which operates gas and electric distribution assets in places like California and Mexico, along with liquefied natural gas projects in Louisiana and Texas.

In August, Sempra outbid Berkshire for Oncor to move into the Texas power market, which has been more robust because of population growth. That same month, Houston-based Calpine Corp., an independent power producer, agreed to be taken private by a group led by Energy Capital Partners for $17.1 billion in equity and debt.

In October, Dynegy Inc. and Vistra Energy Corp., both in Texas, agreed to merge in a transaction valued at $10.5 billion. The combined company and NRG Energy Inc. would be the only publicly traded merchant-power producers left.

"It's difficult to have a publicly traded, independent-power producer because of the focus on short-term earnings from a Wall Street point of view," said Matt Mooren, an energy markets adviser at PA Consulting Group. "With low gas prices and renewables entering the market, that has made the earnings environment a bit more difficult."

Going South

In Canada, where there aren't many takeover targets available, utilities went shopping south of the border. Calgary-based AltaGas Ltd. agreed to buy gas-utility owner WGL Holdings Inc. in Washington, D.C., for $6.3 billion. Hydro One Ltd., based on Toronto, agreed to acquire Avista Corp. of Spokane, Washington, for $5.2 billion.

Biggest 2017 Utility Deals

Buyer	Target	Enterprise Value
Sempra Energy	Energy Future Holdings Corp.	$18.8 billion
Energy Capital Partners, et. al.	Calpine Corp.	$17.1 billion
Vistra Energy Corp.	Dynegy Inc.	$10.5 billion
AltaGas Ltd.	WGL Holdings Inc.	$6.3 billion
Hydro One Ltd.	Avista Corp.	$5.2 billion

Source: M&A data compiled by Bloomberg   Bloomberg

To be sure, not all the deals have been completed. The Public Utility Commission of Texas has yet to sign off on the Oncor-Sempra and Dynegy-Vistra deals. The regulator already nixed an earlier bid by NextEra Energy Inc. to acquire Oncor.

But the industry continues to consolidate. The number of publicly traded utility companies in America has dropped by a quarter over the past decade to about 100, according to data compiled by Bloomberg.

"The market conditions are still favorable from a financing point of view," said Thomas Flaherty, a senior advisor to Strategy&, a consulting group at PricewaterhouseCoopers LLP. "Money is cheap."

The quest for growth from predictable, regulated businesses led two of the largest electric companies, Duke Energy Corp. and Southern Co., to acquire natural-gas distributors in 2015. Last month, Eversource Energy bought Aquarion Water Co., calling itself the first U.S.-based electric utility with a water utility.

The deals probably will keep coming this year, with low borrowing costs and more clarity on tax reform, according to a Dec. 14 research note from analysts at JPMorgan Chase & Co.

"There is a decent probability that we see some big deals in 2018," said Wood, the Moelis & Co. investment banker.

South Carolina's governor is working on the sale of the state-owned utility, Santee Cooper, after it and Scana abandoned work on the project. NRG Energy Inc. is expected to announce a deal as soon as this month to sell its wind and solar company NRG Yield Inc.

More Deals

"You are going to see a lot of generation assets trade hands" in 2018, said James Schaefer, senior managing director and head of energy, power and energy technology at Guggenheim Partners.

The investor-owned utilities probably will continue to merge as they grapple with sagging demand and aging power grids. Renewables like wind and solar are becoming a bigger share of the U.S. electricity supply, which means more investment and more competition with suppliers who use coal, nuclear power and natural gas.

At the same time, consumers will become more efficient in the future, limiting growth in power use, according to Bloomberg New Energy Finance. A measure of the amount of power needed to drive economic activity in the U.S. will drop 36 percent by 2040, as consumption rises at less than half the rate as the population, BNEF said in its 2017 outlook report. That assumes a big jump in demand for electric vehicles.

"In the end, you'll have some more consolidation," said James Torgerson, chief executive officer of Avangrid Inc., a Connecticut utility that was formed through a $3 billion merger in late

2015. "The things you have to invest in today, it just requires more capital access and bigger balance sheets."

– With assistance by Matthew Monks

(Updates with consultant comment in 16th paragraph.)

In this article

BRK/A
BERKSHIRE HATH-A
326,706.00 USD ▼ -1,644.00 -0.50%

SRE
SEMPRA ENERGY
115.24 USD ▲ +0.37 +0.32%

SCG
SCANA CORP
43.71 USD ▲ +0.75 +1.75%

D
DOMINION ENERGY
74.42 USD ▲ +0.81 +1.10%

NG1
Generic 1st 'NG' Future
4.65 USD/MMBtu ▼ -0.05 -1.13%

DEALS

AUGUST 6, 2018 / 5:11 PM / 3 MONTHS AGO

SJW Group makes $1.1 billion all-cash offer for Connecticut Water

NEW YORK (Reuters) - SJW Group (SJW.N) and Connecticut Water Service Inc (CTWS.O) said on Monday they were changing from a merger to an acquisition agreement, with SJW offering to buy the New England utility for $1.1 billion in cash instead of combining stock.

The switch to an all-cash offer is worth $70 per Connecticut Water share, a 33 percent premium to Connecticut Water's share price prior to the original deal announced in March, according to a joint statement.

It was also higher than the implied $61.86 per share value of the Clinton, Connecticut-based firm under the merger-of-equals transaction, which would have created a combined company in which existing SJW shareholders would hold 60 percent of the stock.

SJW closed 2.3 percent lower, while Connecticut Water was 9 percent higher at $68.50.

To pay for the acquisition, SJW will initially utilize a $975 million bridge loan from financial adviser JP Morgan Chase (JPM.N). Ultimately, the purchase would be covered by debt and between $450 million and $500 million of equity finance.

The new deal aims to conclude in the first quarter of 2019, subject to approvals from Connecticut Water's shareholders, as well as regulators in Connecticut and Maine.

The duo's original all-stock merger announcement in March triggered competing offers from Eversource Energy (ES.N) and California Water Service Group (CWT.N).

“We have converted from a stock-for-stock deal to a cash offer, which will resolve any further market distractions from the inferior proposals,” SJW Chief Executive Eric Thornburg told Reuters, in reference to the actions by Eversource and CalWater.

Switching to an acquisition, versus a merger structure, means that SJW shareholders will no longer be required to vote on approving the deal, the statement said.

Why workers are a top asset in M&A in Eastern Europe

CalWater has an open tender offer to acquire SJW that runs until Sept. 28.

However, asked if the change was aimed at heading off any shareholder challenge to the deal, Thornburg told Reuters it “wasn’t a consideration” and it had received nothing but support from its shareholders.

CalWater declined to comment. A spokesman for Eversource said the company was evaluating developments but, as it has made clear, it will be disciplined in pursuing this or any other transaction.

Reporting by David French in New York; Additional Reporting by Liana B. Baker; Editing by Lisa Shumaker

Our Standards: *The Thomson Reuters Trust Principles.*

BUSINESS NEWS

NOVEMBER 19, 2018 / 10:42 AM / A DAY AGO

U.S. home builder sentiment posts biggest drop in 4-1/2 years

FILE PHOTO: A home for sale sign hangs in front of a house in Oakton, on the day the National Association of Realtors issues its Pending Home Sales for February report, in Virginia March 27, 2014. REUTERS/Larry Downing

(Reuters) - U.S. home builder sentiment recorded its steepest one-month drop in over 4-1/2 years in November as rising mortgage rates and tight home inventory squeezed the real estate sector, the National Association of Home Builders said on Monday.

The NAHB and Wells Fargo housing market index fell to 60 points in November, which was the lowest level since the 59 recorded in August 2016. That compared with a reading of 68 in October and a consensus reading of 67 among analysts polled by Reuters.

The index's eight-point drop was the biggest monthly decline since a 10-point decrease in February 2014.

The index's seasonally-adjusted component on current single-family home sales decreased to 67, the lowest since August 2016, from 74 in the prior month.

The seasonally-adjusted gauge on expectations of home sales in six months tumbled to 65 in November, matching the level last seen in May 2016. It was 75 in October.

The barometer on home builders' view on prospective buyers declined to 45, the lowest level since July 2016 and below 53 in October.

Reporting by Richard Leong; Editing by Paul Simao

Our Standards: *The Thomson Reuters Trust Principles.*

Apps Newsletters Advertise with Us Advertising Guidelines Cookies Terms of Use Privacy

All quotes delayed a minimum of 15 minutes. See here for a complete list of exchanges and delays.

Search the site Go ›

Press Release

Print page

<< Back

Aqua America Announces Agreement to Acquire Peoples

Oct 23, 2018

Resulting company will create leading, Pennsylvania-headquartered regulated water and natural gas infrastructure company

- **The resulting company will:**
  - **Serve 1 million water utility customer connections and more than 740,000 gas utility customer connections**
  - **Have projected annual rate base growth of 7 percent water and 8 to 10 percent natural gas through 2021**
  - **Retain corporate and water headquarters in Bryn Mawr and natural gas headquarters in Pittsburgh**
  - **Maintain an accelerated infrastructure replacement strategy focused on utility infrastructure reliability that also ensures jobs and growth**
- **Create a larger, more diversified, fully regulated water and natural gas utility with stable capital structure and long-term growth opportunities through significant infrastructure investment**
- **Transaction is expected to be immediately accretive to earnings the first full year after close and over the long term**

BRYN MAWR, Pa.--(BUSINESS WIRE)--Oct. 23, 2018-- Aqua America Inc., (NYSE:WTR) ("Aqua") a regulated water and wastewater utility, today announced it will acquire Peoples in an all-cash transaction that reflects an enterprise value of $4.275 billion, which includes the assumption of approximately $1.3 billion of debt. This acquisition marks the creation of a new infrastructure company that will be uniquely positioned to have a powerful impact on improving the nation's infrastructure reliability, quality of life and economic prosperity.

Peoples consists of Peoples Natural Gas Company LLC, Peoples Gas Company LLC and Delta Natural Gas Company Inc. The multi-platform entity brings together the second-largest U.S. water utility and fifth-largest U.S. stand-alone natural gas local distribution company (based on customers), and will serve 1.74 million customer connections, which represent approximately 5 million people. In 2019, the new company will have approximately $10.8 billion in assets and a projected U.S. regulated rate base of over $7.2 billion. The transaction is not expected to have any impact on rates.

The combined enterprise will be among the largest publicly traded water utilities and natural gas local distribution companies in the U.S., uniquely positioned to meaningfully contribute to the nation's natural gas and water infrastructure reliability. The transaction will bring together two companies that each have more than 130 years of service and proven track records of operational efficiency, complementary service territories and strong regulatory compliance.

Aqua will acquire Peoples from infrastructure funds managed by Sausalito, California-based SteelRiver Infrastructure Partners. The resulting company will be well positioned to grow and generate shareholder value through increased scale, a balanced portfolio and stable capital structure.

"The acquisition of Peoples is a great strategic fit and aligns directly with our growth strategy and core competencies of building and rehabilitating infrastructure, timely regulatory recovery, and operational excellence," said Aqua Chairman and CEO Christopher Franklin. "Both Aqua and Peoples place customers at the center of all we do. We care deeply for employees and their safety, have expertise in pipe replacement, and prioritize stewardship of the environment. Both companies have worked hard to earn credibility with regulators and respect of other stakeholders, and to employ advanced operational efficiencies, all of which create long-term value for customers, communities, employees and shareholders."

The combined company will operate regulated utilities over a 10-state footprint and will have its largest concentration in Pennsylvania, which will account for more than 77 percent of the company's total rate base. Aqua's rate base is growing annually at approximately 7 percent (2019-2021) and Peoples' rate base is growing annually at 8 to 10 percent (2019-2021), creating a strong combined growth trajectory.

"By bringing together water and natural gas distribution utility companies that share a core mission of providing essential services to customers, the resulting company will be positioned to grow and drive value, as well as make a long-term, positive contribution to our nation's infrastructure challenges and ensure service reliability for generations to come," Franklin said. "The new leadership team will take an integrated management approach to cooperatively running the utilities. We plan to leverage the combined breadth of experience from both companies to lead our new combined company."

Morgan O'Brien, who will continue to lead the natural gas company, said, "The planned combination with Aqua creates a larger strategic utility committed to growing our region's economic future using the most responsible and innovative tools in our long-term infrastructure replacement programs in Pennsylvania, West Virginia and Kentucky. Our resulting company is deeply rooted in the long-established regulatory environments where partnership opportunities will support growth and safety. We are focused on strongly encouraging infrastructure replacement and expansion to better serve customers and fuel growth opportunities. In addition, this larger entity will provide employees with enhanced opportunities for career development.

"For example, the Pennsylvania Public Utility Commission has demonstrated its support for our infrastructure investment program, through which we will replace more than 3,100 miles of bare steel and cast-iron pipe in the coming years at a current rate of about 150 miles per year," said O'Brien.

Post-transaction close, the combined businesses will be led by Franklin. The company's corporate headquarters will be in Bryn Mawr, Pennsylvania, and Aqua's water and wastewater operations will remain headquartered in Bryn Mawr. Peoples, the natural gas operating subsidiary, and its employees will remain headquartered in Pittsburgh and other operating locations will remain unchanged.

Transaction details

The transaction is anticipated to be immediately accretive to earnings the first full year after close and over the long term. Management anticipates enhanced future earnings growth and continued long-term dividend growth. Significant growth in rate base and earnings is expected to be driven by pipe-replacement capital expenditures, new customer connections and continued success in municipal acquisitions. As a larger publicly traded utility, the resulting company will have enhanced ability to access capital and fund its infrastructure and capital expenditure needs.

The all-cash transaction reflects an enterprise value of Peoples of $4.275 billion, which includes the assumption of approximately $1.3 billion of debt. The acquisition is supported by a fully committed bridge facility. Permanent financing will include an appropriate mix of equity and debt to target a strong balance sheet and investment-grade credit ratings.

The transaction is subject to regulatory approvals, including approval by the public utility commissions in Pennsylvania, Kentucky and West Virginia. Assuming fulfillment of those conditions, closing of the transaction is expected in mid-2019.

Following closing, the company's operational makeup will consist of greater than 99 percent in regulated utilities. Total rate base is expected to exceed $7.2 billion, with approximately 70 percent in water and wastewater and 30 percent in natural gas. Total rate base is expected to grow approximately 7 percent a year for Aqua and 8 to 10 percent a year for Peoples through 2021.

2018 Aqua Guidance

Aqua reaffirms the prior guidance and qualifies its earnings per diluted common share range to be exclusive of transaction expenses associated with the Peoples transaction.

- Earnings per diluted common share of $1.37 to $1.42, excluding transaction expenses
- Infrastructure investments of approximately $500 million in 2018 for communities served by Aqua
- Infrastructure investments of approximately $1.4 billion through 2020 in existing operations to improve and strengthen systems
- Total customer growth of between 2 and 3 percent for 2018
- Aqua Pennsylvania filed a rate case in August 2018 with resolution expected in 2019

Advisors
Moelis & Company LLC is serving as the lead financial advisor to Aqua. Goldman Sachs & Co. LLC and RBC Capital Markets are also serving as financial advisors to Aqua, and Goldman Sachs Bank USA and Royal Bank of Canada are providing the fully committed bridge facility. Simpson Thacher & Bartlett LLP is serving as legal advisor to Aqua.

Morgan Stanley & Co. LLC is serving as financial advisor to the seller, and Winston & Strawn LLP is the seller's legal advisor.

Analyst call information

Date: Oct. 23, 2018

Time: 8:30 a.m. EDT (please dial in by 8:15 a.m.)

Webcast and slide presentation link: http://ir.aquaamerica.com/events-&-presentations

Replay Dial-in #: 888.203.1112 (U.S.) & +1 719.457.0820 (International)

Confirmation code: 9368677

A conference call with financial analysts will take place on Oct. 23 at 8:30 a.m. Eastern Daylight Time. The call and slide presentation will be webcast live so that interested parties may listen over the internet by logging on to AquaAmerica.com and following the link for Investor Relations. The webcast will be archived in the investor relations section of the company's website for 90 days following the call. Additionally, the call will be recorded and made available for replay at 2 p.m. on Oct. 23, 2018 for 10 business days following the call. To access the audio replay in the U.S., dial 888.203.1112 (pass code 9368677). International callers can dial +1 719.457.0820 (pass code 9368677).

Organizational information

Aqua America is a 132-year-old regulated water and wastewater utility whose 1,600 employees serve 3 million people in Pennsylvania, Ohio, North Carolina, Illinois, Texas, New Jersey, Indiana and Virginia. Headquartered in Bryn Mawr, Pennsylvania near Philadelphia, Aqua's mission is to protect and provide Earth's most essential resource for the customers and communities it serves. Aqua's subsidiaries treat and deliver water through thousands of miles of distribution pipe to customers in its footprint. Its team of dedicated experts helps ensure a safe and reliable drinking water supply, and a professional team of engineers and operators helps plan, design and install about 150 miles of distribution pipe every year. The team performs its work with integrity, respect and the pursuit of excellence at the forefront of all it does. Since 1995, Aqua has added and successfully integrated water and wastewater systems from 300 acquisitions to its family.

Peoples is a 133-year-old natural gas company headquartered in Pittsburgh, Pennsylvania, with about 1,500 employees who live and work in the communities it serves. Owned by infrastructure funds managed by SteelRiver Infrastructure Partners since 2010, Peoples is the largest natural gas distribution company in Pennsylvania, providing reliable, low-cost natural gas distribution service to approximately 740,000 customers in Western Pennsylvania, West Virginia, and Kentucky. In the last 7 years, Peoples purchased the T.W. Phillips Gas & Oil Company and Equitable Gas, adding service territories in West Virginia and Kentucky. In 2017, Peoples closed its purchase of Delta Natural Gas, which retains this brand name and is headquartered in Winchester, Kentucky. In the past 8 years, Peoples has grown its customer base from approximately 360,000 customers to over 740,000 customers.

Caution concerning forward-looking statements

This release contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, including, among other statements regarding: the anticipated impact of the transaction on the company's earnings; anticipated growth rates; the expected timing of the closing of the transaction; financing for the transaction; the anticipated year-end earnings per share results; and the anticipated amount of capital investment through 2018. There are important factors that could cause actual results to differ materially from those expressed or implied by such forward-looking statements including: the company's ability to obtain the necessary regulatory approvals on a timely basis or at all; the company's ability to integrate the acquired business; the company's ability to achieve the projected synergies in connection with the proposed transaction and to grow the combined business; general economic business conditions; the company's ability to fund needed infrastructure due to its financial position; housing and customer growth trends; unfavorable weather conditions; the success of certain cost containment initiatives; changes in regulations or regulatory treatment; availability and access to capital; the cost of capital; disruptions in the credit and equity markets (including without limitation disruptions that could affect access to capital anticipated for the consummation of the contemplated transaction); the success of growth initiatives; the company's ability to execute on its core capabilities of prudently deploying capital, consistently earning credibility with stakeholders, and maintaining its status as one of the most efficient utilities in the United States; and other factors discussed in our Annual Report on Form 10-K, which is on file with the Securities and Exchange Commission. For more information regarding risks and uncertainties associated with Aqua America's business, please refer to Aqua America's annual, quarterly and other SEC filings. Aqua America is not under any obligation – and expressly disclaims any such obligation – to update or alter its forward-looking statements whether as a result of new information, future events or otherwise.

WTRF

View source version on businesswire.com: https://www.businesswire.com/news/home/20181023005590/en/

Source: Aqua America Inc.

Aqua America Inc.
Brian Dingerdissen, 610-645-1191
Investor Relations
BJDingerdissen@AquaAmerica.com
or
Stacey Hajdak, 610-520-6309 (O)
267-294-1866 (M)
Communications and Marketing
SMHajdak@AquaAmerica.com

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY-AMERICAN WATER COMPANY FOR AN ADJUSTMENT OF RATES SUPPORTED BY A FULLY FORECASTED TEST YEAR	))))	CASE NO. 2012-00520

TABLE OF CONTENTS

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY-AMERICAN WATER COMPANY FOR AN ADJUSTMENT OF RATES SUPPORTED BY A FULLY FORECASTED TEST YEAR	))))	CASE NO. 2012-00520

ORDER

Kentucky-American Water Company ("Kentucky-American") has applied to adjust its rates for water service to produce additional revenues of $12,317,702, or 15.05 percent, over forecasted operating revenues from existing water rates of $81,832,138.[1] By this Order, we establish rates that will produce an annual increase in revenues from water sales of $6,904,134, or 8.25 percent, over adjusted forecasted revenues from water sales of $83,642,642; deny Kentucky-American's request to establish a Distribution System Improvement Charge and a Purchased Power and Chemical Charge; and approve adjustments to Kentucky-American's nonrecurring charges.

BACKGROUND

Kentucky-American, a Kentucky corporation, owns and operates water production and distribution facilities that provide water service to 124,344 customers in Bourbon, Clark, Fayette, Gallatin, Grant, Harrison, Jessamine, Owen, Scott, and Woodford counties, Kentucky.[2] It provides wholesale water service to Harrison County

---

[1] As required by KRS 278.192(2)(b), Kentucky-American submitted its base period update on May 15, 2013, to report the actual results for the base period months that were originally forecasted. This update contains corrections of certain errors and the "slippage" that result in a revised revenue increase of $12,068,431, or $249,271 below the originally proposed increase.

[2] *Annual Report of Kentucky-American Water Company to the Public Service Commission for the Calendar Year Ended December 31, 2012* at 5, 30.

Water Association, East Clark Water District, Peaks Mill Water District, Jessamine-South Elkhorn Water District, and the cities of Georgetown, Midway, North Middletown, Nicholasville, and Versailles.[3] It directly or indirectly provides potable water service to approximately 490,000 persons.[4] Kentucky-American last applied for a rate adjustment in 2010.[5]

Kentucky-American is currently organized into two divisions: Northern Division and Central Division. The Northern Division consists of all facilities located in Gallatin, Grant, and Owen counties, Kentucky. As of May 31, 2012, the Northern Division had approximately 3,862 customers.[6] Kentucky-American's remaining facilities compose the Central Division. The Central Division has approximately 120,500 customers.

PROCEDURE

On November 29, 2012, Kentucky-American notified the Commission in writing of its intent to apply for an adjustment of rates using a forecasted test period. On December 28, 2012, it submitted its application. The Commission established this docket and permitted the following parties to intervene in this matter: the Attorney General of Kentucky ("AG"), Lexington-Fayette Urban County Government ("LFUCG"), and Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC").

---

[3] *Id.* at 33.

[4] *See* http://www.amwater.com/kyaw/about-us/ (last visited Oct. 20, 2013).

[5] Case No. 2010-00036, *Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year* (Ky. PSC Dec. 14, 2010).

[6] Case No. 2012-00096, *Application of Kentucky-American Water Company for a Certificate of Public Convenience and Necessity Authorizing Construction of the Northern Division Connection*, Kentucky-American's Response to Commission Staff's First Request for Information, Item 33 (filed July 23, 2012).

On January 22, 2013, the Commission suspended the operation of the proposed rates for six months and established a procedural schedule for this proceeding. Following discovery, the Commission held an evidentiary hearing in this matter on June 4-5, 2013, in Frankfort, Kentucky.[7] We also conducted a public meeting in Lexington, Kentucky, on May 28, 2013 to receive public comment on the proposed rate adjustment. All parties submitted written briefs following the conclusion of the evidentiary hearing.

On July 26, 2013, Kentucky-American notified the Commission of its intent to place the proposed rates into effect for service rendered on and after July 27, 2013. In response, we directed Kentucky-American to maintain appropriate records of its billing to permit any necessary refunds.

[7] The following persons testified at the evidentiary hearing: Cheryl Norton, President, Kentucky-American; Keith Cartier, Vice President of Operations, Kentucky-American; Scott Rungren, Financial Analyst, American Water Works Service Company, Central Division; Melissa Schwarzell, Financial Analyst, American Water Works Service Company, Central Division; Linda C. Bridwell, Manager Rates and Regulation for Kentucky and Tennessee, American Water Works Service Company; Gary VerDouw, Director of Rates, American Water Works Service Company, Central Division; Carl Meyers, Director of Income Tax, American Water Works Company; David Baker, Vice President, American Water Works, North East Division, and President, New Jersey-American Water Company; Paul R. Herbert, President, Valuation and Rate Division, Gannett Fleming, Inc.; Stephen M. Rackers, Consultant, Brubaker and Associates, Inc.; Brian Kalcic, Principal, Excel Consulting; William O'Mara, Commissioner of Finance, LFUCG; and Jack E. Burch, Executive Director, CAC. The following persons submitted written testimony but did not appear at the evidentiary hearing: Lance Williams, Director of Engineering for Kentucky and Tennessee, American Water Works Service Company; Lewis Keathley, Financial Analyst, American Water Works Service Company, Central Division; Jermaine Bates, Rates Analyst, American Water Works Service Company, Central Division; James H. Vander Weide, Professor of Finance and Economics, Duke University; and J. Randall Woolridge, Professor of Finance, Pennsylvania State University. After the hearing, Witnesses Meyers, Vander Weide, and Woolridge responded to written questions from Commission Staff.

ANALYSIS AND DETERMINATION

Test Period

Kentucky-American uses as its forecasted test period the 12-month period ending July 31, 2014.[8] Its base period is the 12-month period ending March 31, 2013.[9]

Rate Base

Kentucky-American proposes a forecasted net investment rate base of $385,994,706.[10] The Commission accepts this forecasted rate base with the following exceptions:

Utility Plant in Service ("UPIS"). Kentucky-American uses capital construction budgets to determine its forecasted UPIS amount of $627,540,378.[11] Kentucky-American separates its construction budgets into three categories: normal recurring construction, construction projects funded by others,[12] and major investment projects.

In prior rate proceedings, the Commission has adjusted forecasted UPIS to reflect 10-year historical trend percentages of actual-to-budgeted construction

---

[8] Application ¶ 7.

[9] *Id.* ¶ 8.

[10] *Id.* Ex. 37, Sch. B-1 at 2.

[11] *Id.*

[12] Contributions in Aid of Construction or Customer Advances, which are forms of cost-free capital, fund these projects.

spending.[13] In support of our action, we have noted the imprecision of the budgeting process:

> Budgeting being an inexact science, it is imperative that the historical relationship between the budgets and actual results be reviewed to determine what projects Kentucky-American is likely to have in service or under construction in the forecasted period. A forecasted period does not preclude the examination of historic data and trends but, rather, compels their examination to test the historic to forecasted relationships. Nor will an adjustment based on the historical slippage factor have a devastating impact on Kentucky-American's earning potential. Such an adjustment will have a minimal impact on revenue requirements by eliminating a return on utility plant not in service during the forecasted period due to delayed investment.[14]

These "slippage factors" thus serve as an indicator of Kentucky-American's accuracy in predicting the cost of its utility plant additions and the time period during which new plant will be placed into service.

Kentucky-American did not propose a slippage factor adjustment to its forecasted construction budget in its application. In its base period update, however, it revised its revenue requirement to reflect the effect of a slippage adjustment on its forecast.[15] Applying a slippage factor for normal recurring construction and major investment projects of 122.14 percent and 82.25 percent respectively to its capital construction

---

[13] *See, e.g.*, Case No. 92-452, *Notice of Adjustment of Rates of Kentucky-American Water* Company (Ky. PSC Nov. 19, 1993) at 9 - 11; Case No. 95-554, *The Application of Kentucky-American Water Company to Increase Its Rates* (Ky. PSC Sep. 11, 1996) at 2 - 3; Case No. 97-034, *The Application of Kentucky-American Water Company to Increase Its Rates* (Ky. PSC Sep. 30, 1997) at 3 - 7; Case No. 2000-120, *The Application of Kentucky-American Water Company to Increase Its Rates* (Ky. PSC Nov. 27, 2000) at 2 - 4; Case No. 2004-00103, *Adjustment of the Rates of Kentucky-American Water Company* (Ky. PSC Feb. 28, 2005) at 3 - 4; and Case No. 2010-00036, Order of Dec. 14, 2010 at 4 - 7.

[14] Case No. 92-452, Order of Nov. 19, 1993 at 9.

[15] Rebuttal Testimony of Linda C. Bridwell at 2; Base Period Update-Revised Ex. 37, Sch. B-2 at 2 (filed May 25, 2013).

budgets,[16] Kentucky-American calculated its forecasted UPIS to be $629,839,138, or $2,298,760 greater than the original forecasted UPIS of $627,540,378.[17] In support of its use of a slippage adjustment above 100 percent, Kentucky-American refers to two prior Commission decisions in which we allowed such reverse slippage adjustments.[18]

Although initially opposing the use of a reverse slippage adjustment,[19] the AG subsequently reversed his position and now supports Kentucky-American's proposed adjustment. While having "qualms about the use of a slippage factor mechanism to increase the Company's revenue requirement,"[20] the AG states that the slippage factor served as "an effective regulatory device to correct . . . [Kentucky-American's] former

---

[16] For the comparison of actual-to-budgeted construction spending for the 10-year period ending December 31, 2011, see Kentucky-American's Response to Commission Staff's First Request for Information, Item 11(a) (filed January 23, 2013). In its second discovery request, Commission Staff calculated the slippage factors and requested that Kentucky-American apply those factors to all monthly Recurring Capital Expenditure Projects expenditures beginning December 2009 through the end of the forecasted test period. *See* Commission Staff's Second Request for Information, Item 41 (filed Feb. 6, 2013).

[17] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 41, Schedule B-1 at 2.

[18] Case No. 2010-00036, Order of Dec. 14, 2010; Case No. 2005-00042, *An Adjustment of the Gas Rates of the Union Light, Heat and Power Company* (Ky. PSC Dec. 22, 2005).

[19] *See* AG's Response to Commission Staff's Request for Information, Item 26 (filed May 1, 2013) ("The Attorney General does not agree with or support the use of an adjustment consequent to a pattern of underbudgeting. It removes an incentive for KAW [Kentucky-American] to accurately budget and properly implement its capital construction program."). In response to a discovery request, AG witness Stephen M. Rackers states:

> KAWC is in possession of all the information regarding its operations, including the budgeting function and construction program. KAWC also controls the timing and completion of the various construction projects. As a result the risk of including the proper level of forecasted plant should be borne by KAWC.
>
> Therefore, the ratepayer protection of a slippage adjustment should not also serve as a mechanism to increase revenue requirement due to potential under budgeting. The incentive for KAWC to control cost is also diminished by allowing a slippage adjustment to increase forecasted construction.

AG's Response to Commission Staff's Request for Information, Item 28.

[20] AG Brief at 4.

'pervasive pattern of overbudgeting for its construction.'"[21] He noted that it "protects ratepayers from overbudgeting and also properly serves to provide the utility with a measure of protection (and risk management)."[22]

We find that a reverse slippage factor adjustment in this proceeding is appropriate and consistent with our prior holdings. In Case No. 2010-00036, we noted that the purpose of the slippage factor "is to produce a more accurate, reasonable, and reliable level of forecasted construction."[23] The application of slippage factors in this proceeding is consistent with that purpose. Accordingly, we find that Kentucky-American's forecasted UPIS should be increased by $2,298,760 to reflect the application of slippage factors for normal recurring construction and major investment projects of 122.14 percent and 82.25 percent respectively.

Business Transformation ("BT") Program. American Water Works Company[24] ("AWWC"), Kentucky-American's parent corporation, is developing and deploying several new, integrated information technology systems to manage the following core functional areas of AWWC and its subsidiaries: human resources, finance and accounting, purchasing and inventory management, capital planning, and customer and field services.[25] The project, which AWWC has named the "Business Transformation"

---

[21] *Id.*

[22] *Id.* at 5.

[23] *See* Order of Dec. 14, 2010 at 7.

[24] AWWC, a Delaware corporation, is the largest, investor-owned water and wastewater utility company in the United States. Its 15 regulated subsidiaries currently provide water and wastewater services in 16 states. AWWC currently owns all outstanding shares of Kentucky-American stock. *See* http://www.amwater.com/About-Us/our-subsidiaries.html (last visited Oct. 23, 2013).

[25] Direct Testimony of Gary M. VerDouw at 36 - 37.

("BT") Program, is intended to replace legacy information technology systems, promote greater efficiency, improve customer service, and increase employee effectiveness.[26]

AWWC estimates the BT Program's total cost to be $320.3 million.[27] It intends to allocate this cost to each of its regulated utilities based on the percentage of their customer counts to the overall AWWC regulated utility customer count.[28] This method of allocation is consistent with the terms of the 1989 agreement between American Water Works Service Company and Kentucky-American.[29] AWWC projects an allocation of $12,290,381 of total BT Program costs to Kentucky-American. According to Kentucky-American Witness Gary VerDouw, this cost "equates to a cost of just over $100 per Kentucky American customer, or approximately $10 per year per customer based on the anticipated life of ten years for the BT assets."[30] AWWC will have billed Kentucky-American for its share of BT Program costs to Kentucky-American by 2014.[31] Approximately $11,027,990 of Kentucky-American's forecasted UPIS is attributable to BT Program assets.[32]

---

[26] *Id.* at 36.

[27] *Id.* at 37.

[28] *Id.* at 37, 46 - 47.

[29] Agreement between American Water Works Service Co. and Kentucky-American Water Company ("Service Agreement") (Jan. 1, 1989) (available at Kentucky-American's Response to Commission Staff's First Request for Information, Item 32). ¶ 2.4 provides: "All costs incurred in rendering services to Water Company in common with similar services to other Water Companies which cannot be identified and related exclusively to services rendered to a particular Water Company, shall be allocated among all water Companies so served, or, in the case of costs incurred with respect to a particular group of Water Companies, among the members of such group, based on the number of customers served at the immediately preceding calendar year end."

[30] Direct Testimony of Gary M. VerDouw at 37. Kentucky-American indicated that BT Program assets have a ten-year useful life and should be depreciated over a ten-year period. *Id.* at 50 - 51.

[31] *Id.* Ex. BT-1 at 1.

[32] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 41 at 122.

The BT Program consists of three information systems: Enterprise Resource Planning; Enterprise Asset Management; and Customer Information System. AWWC deployed the Enterprise Resource Planning system in August 2012.[33] Deployment of the remaining systems began in 2013.[34]

LFUCG opposes inclusion of the BT Program assets into Kentucky-American's rate base for ratemaking purposes.[35] It argues that Kentucky-American has failed to meet its burden of proof that the program is reasonable. More specifically, it notes the absence of any Kentucky-American specific study regarding the program and the lack of any study of possible alternatives to the BT Program.[36]

Our review of the evidence indicates sufficient evidence to support inclusion of the BT Program costs into UPIS. The evidence of record indicates that Kentucky-American's information infrastructure was approaching the end of its useful life and a need to replace the system existed. Most of Kentucky-American's information system had been in service since the 1990s or the early part of the last decade.[37] These systems were not integrated and had limited functionality. They could not perform many of the customer-service technology functions that the public has come to expect.[38]

---

[33] *Id.* at 43.

[34] *Id.*

[35] In his brief, the AG took no position on the BT program. In response to discovery requests, AG Witness Rackers stated that without a cost-benefit analysis study that considered whether Kentucky-American could have developed or purchased its own system that met its needs and cost less than $12 million, no determination could be made regarding the reasonableness of the BT Program costs. AG's Response to Commission Staff's Request for Information, Item 20.

[36] LFUCG Brief at 5.

[37] Direct Testimony of Gary M. VerDouw at 38; Kentucky-American's Response to Commission Staff's Third Request for Information, Item 25.

[38] These services include internet billing, appointments for repair calls, self-service inquiry and ordering capabilities, and secure transfer of personal information.

Some supporting software for these systems was no longer available. Moreover, while the lives of some systems could be extended through system customizations, numerous customizations would be required and would be expensive.[39]

The record further indicates that a reasonable and thorough review process was used to determine the needs of AWWC's utilities and to procure the information technology systems. AWWC performed a comprehensive study of its needs.[40] It used a competitive bidding and evaluation process to select its information systems and system integrator. AWWC conducted "extensive analyses of potential service providers, used competitive bidding processes to select key service providers and negotiated 'not to exceed' fixed fee arrangements to ensure effective cost control."[41] Throughout the process it solicited and received comments and input from these corporate stakeholders, including Kentucky-American officials.[42]

BT Program costs compare favorably to similar-sized customer-service information system projects that other utilities in this state have undertaken. The cost of the customer service portion of Kentucky-American's BT Program is approximately $30 per customer.[43] In contrast, Louisville Water Company recently installed a customer-care information system at a cost of $92 per customer. Louisville Gas and Electric

---

[39] Direct Testimony of Gary M. VerDouw at 39 - 40.

[40] AWWC, *American Water information Technology Infrastructure Comprehensive Planning Study Report* ("*Comprehensive Planning Study Report*") (Voorhees, N.J. Apr. 13, 2010) (available at Kentucky-American's Response to AG's First Request for Information, Item 168).

[41] Kentucky-American's Response to Commission Staff's Third Request for Information, Item 25.

[42] Rebuttal Testimony of Gary M. Verdouw at 3 - 4.

[43] The total cost of BT Program, not merely the customer-service technology portion, is approximately $100 per customer. *See supra* note 30 and accompanying text.

Company and Kentucky Utilities Company jointly installed a customer-care and billing-information system project whose cost is roughly $68 per customer.[44]

While the record does not indicate any Kentucky-specific analysis of the BT Program, Kentucky-American has identified several benefits that will inure to its customers as a result of the BT Program. These include:

> (1) Optimizing material availability to field personnel, which will enhance the quality and timeliness of field service; (2) increasing efficiencies in recruiting process to minimize work gaps and ensure continuity of service for customers; (3) improving asset reliability and fewer unexpected outages by optimizing reliability-centered maintenance programs; (4) proactively communicating to customers through automated phone messages about incidents in their area; (5) improving employee dispatch, thereby enhancing customer solutions and response times; (6) greater first contact resolution as a result of automation in the bill correction process and redirected resources providing the opportunity to resolve customer requests in a timely manner; (7) opportunities for enhanced bill presentment options; (8) ability to introduce tools that would assist customers in resolving debt issues and eliminate manually intensive collection processes; (9) improving scheduling between field service representatives and customers; and (10) the ability to track service orders that will allow customers to monitor the progress online.[45]

It has also provided evidence of the alternatives that were considered and a reasonable basis for its rejection of those alternatives.[46]

We find that Kentucky-American has adequately demonstrated that the BT Program was necessary for Kentucky-American to meet its service obligations; BT Program assets are currently in use to serve Kentucky-American customers; and, BT

---

[44] VR 06052013; 15:13:17 - 15:15:37.

[45] Kentucky-American Brief at 56; *Comprehensive Planning Study Report* at 37 - 39.

[46] *See* Rebuttal Testimony of Gary M. Verdouw at 4 - 5, *Comprehensive Planning Study Report* at 56 - 57.

Program costs were not unreasonable or excessive. Accordingly, we deny LFUCG's proposed adjustment to remove BT Program assets from UPIS.[47]

Accumulated Depreciation. Kentucky-American uses a 13-month average of its accumulated depreciation balances for the period from July 1, 2013, through July 31, 2014, to arrive at forecasted accumulated depreciation of $136,601,885.[48] The Commission finds that forecasted accumulated depreciation should be increased by $31,332 to reflect the effect of construction slippages, which results in an adjusted balance of $136,633,217.[49]

Construction Work in Progress ("CWIP"). Kentucky-American uses capital construction budgets for the period from July 1, 2013, through July 31, 2014, to calculate forecasted CWIP of $6,851,268.[50] The Commission finds that Kentucky-American's forecasted CWIP should be decreased by $554,089 for an adjusted balance of $6,297,179 to reflect the effect of construction slippages.[51]

Working Capital. In its application, Kentucky-American includes a cash working capital allowance of $3,946,000 in its forecasted rate base.[52] It subsequently revised its

---

[47] As Kentucky-American has demonstrated BT Program's benefits and costs, our decision in this case is easily distinguishable from other proceedings in which applicants have failed to make such showing. *See, e.g.*, Case No. 2008-00563, *Application of Water Service Corporation of Kentucky for an Adjustment of Rates* (Ky. PSC Nov. 9, 2009).

[48] Application, Ex. 37, Sch. B-1, at 2.

[49] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 41 at 38.

[50] Application Ex. 37, Sch. B-4.1 at 2.

[51] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 41 at 38.

[52] Application Ex. 37, Sch. B-5.2 at 4.

calculation of cash working capital to remove federal income tax from net income[53] and reflect the effects of slippage.[54] These revisions reduce cash working capital by $854,000 to $3,092,000.[55] Kentucky-American used a lead/lag study that employs the methodology approved in prior Kentucky-American rate proceedings to calculate cash working capital allowance and includes non-cash expenses and common equity profits.

The AG proposes the removal of a working capital component from the rate base.[56] Although conceding that working capital is necessary to recognize the lag between the collection of funds from the ratepayers to pay for the cash expenses that are necessary to fund Kentucky-American's daily operations, the AG argues that non-cash expenses and common equity profits should not be considered in the calculation of working capital, since these items are not cash expenses necessary to fund daily operations.[57] He further argues that, if these items are not considered, the revenue requirement associated with working capital is immaterial and should not be considered.[58]

Opposing this proposal, Kentucky-American notes the Commission has consistently rejected the AG's position in numerous proceedings over the last 20 years.[59] It argues that the proposal should be rejected in light of the Commission's

---

[53] Rebuttal Testimony of Linda C. Bridwell at 2.

[54] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 41 at 38.

[55] Base Period Update Filing, Ex. 37, Sch. B-5.2 at 4.

[56] Direct Testimony of Stephen M. Rackers at 19.

[57] *Id.* at 15; AG Brief at 13.

[58] Direct Testimony of Stephen M. Rackers at 15.

[59] Kentucky-American Brief at 9 - 11.

longstanding precedent and in the absence of any new argument or support for the AG's position.

Kentucky-American's lead/lag study uses the methodology that the Commission has generally accepted since 1983.[60] Our review of past Kentucky-American rate adjustment proceedings indicates that the AG has consistently presented, and the Commission has consistently refused to adopt, his argument regarding working capital.[61] The AG has offered no new evidence or argument in the current proceeding to disturb our previous findings or to require a change in the Commission's position on this matter. We find his proposal regarding cash working capital should be denied.

After applying all reasonable and necessary adjustments to Kentucky-American's forecasted working capital calculation, the Commission finds the appropriate working capital allowance to be $2,406,000, a decrease of $1,540,000 to Kentucky-American's forecasted level of $3,946,000.

<u>Contributions in Aid of Construction ("CIAC")</u>.[62] In its application, Kentucky-American includes CIAC of $52,238,690[63] as a reduction to rate base. We find that this

[60] Case No. 8314, *Notice of Adjustment of Rates of Kentucky-American Water Company* (Ky. PSC Feb. 8, 1982) at 6.

[61] *See, e.g.*, Case No. 10069, *Notice of Adjustment of the Rates of Kentucky-American Water Company* (Ky. PSC July 31, 1996) at 6 – 8; Case No. 92-452, *Notice of Adjustment of the Rates of Kentucky-American Water Company* (Ky. PSC Nov. 19, 1993) at 17 – 21; Case No. 95-554, *Notice of Adjustment of the Rates of Kentucky-American Water Company* (Ky. PSC Sept. 11, 1996) at 21 – 24; Case No. 97-034, *Notice of Adjustment of the Rates of Kentucky-American Water Company* (Ky. PSC Sept. 30, 1997) at 25 – 28; Case No. 2004-00103, *Adjustment of the Rates of Kentucky-American Water Company* (Ky. PSC Feb. 28, 2005) at 17.

[62] For a definition of CIAC, see Direct Testimony of Linda C. Bridwell at 28 ("a reduction in rate base that recognizes the value of mains, meters, services or hydrants that are paid for by a third party and thus are not an investment by KAW [Kentucky-American], but fully owned and maintained by the Company."

[63] Application Ex. 37, Sch. B-1 at 2.

amount should be increased by $813,001, to $53,051,691, to reflect the effects of construction slippage.[64]

Customer Advances.[65] In its application, Kentucky-American identifies customer advances as $13,997,843.[66] The Commission finds that customer advances should be increased by $179,147 to $14,176,990, to reflect the effects of construction slippage.[67]

Deferred Maintenance. Kentucky-American incurs maintenance expenses (e.g., tank and hydrator painting and repairs, station cleaning) for which the Commission has historically allowed deferred accounting treatment. With such expenses, Kentucky-American is permitted annual recovery of allowed amortization expense. The unamortized balance of these expenses is generally included in rate base.

In its application, Kentucky-American proposes the inclusion of $4,644,233 of deferred maintenance in its rate base.[68] The allowed amounts are based on actual costs from historical periods and forecasted costs. Among the forecasted maintenance projects whose costs will be deferred are six new tank paintings.[69] The Commission finds that Kentucky-American's forecasted deferred maintenance of $4,644,233 is reasonable and should be allowed in rate base.

---

[64] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 41 at 38.

[65] For a definition of Customer Advances, see Direct Testimony of Linda C. Bridwell at 27 ("a reduction to rate base to recognize money collected for new mains that are held in an account and refunded to the original customer as new customers tap onto a main").

[66] Application Ex. 37, Sch. B-1 at 2.

[67] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 41 at 38.

[68] Application Ex. 37, Sch. B-1 at 2.

[69] Direct Testimony of Linda C. Bridwell at 29.

Deferred Taxes. In its application, Kentucky-American reduces rate base by accumulated deferred income tax of $57,007,044.[70] In its base period update, Kentucky-American revises forecasted deferred income taxes upward by $446,815 to $57,453,859 to reflect the effect of construction slippages.[71] Included in deferred income taxes are items approved in prior rate cases: UPIS, deferred maintenance, and deferred debits.[72] Kentucky-American's calculations are consistent with Statement of Financial Accounting Standards ("SFAS") 109 – Accounting For Income Taxes,[73] a methodology that the Commission has previously accepted.[74]

In its calculation of deferred income taxes, Kentucky-American has taken into account a potentially adverse ruling from the Internal Revenue Service ("IRS") on certain accounting practices. On December 31, 2008, Kentucky-American, as a member of a consolidated group of American Water Works Company ("AWWC") subsidiaries, requested authorization from the IRS to change its accounting method for recording repairs and maintenance. Instead of capitalizing repairs and maintenance costs, the members of the consolidated group sought to deduct these costs in the current tax year. In February 2010, the IRS approved the request and Kentucky-American recognized a tax deduction for costs that previously were capitalized for tax

[70] Application Ex. 37, Sch. B-6 at 2.

[71] Base Period Update-Revised Ex. 37, Sch. B-6 at 2; Kentucky-American's Response to Commission Staff's Second Request for Information, Item 41 at 83.

[72] Direct Testimony of Scott W. Rungren at 14.

[73] SFAS 109 is "a balance sheet approach to deferred income taxes that requires the deferred income tax provision be shown in total, but also recognizes the regulatory assets and liabilities that will be recovered in rates in future years." *Id.* at 15.

[74] *See, e.g.*, Case No. 2010-00036, Order of Dec. 14, 2010 at 16 – 17.

purposes.[75] The members of the consolidated group, however, believe that the IRS ruling fails to address a critical component of the deduction calculation, that this failure creates uncertainty regarding the deduction, and that they are potentially subject to additional tax liability.

Kentucky-American maintains that, in light of this uncertainty, Financial Accounting Standards Board Interpretation No. 48 ("FIN 48") requires the creation of a liability account to record the amount of deferred taxes that the IRS would likely deny. FIN 48 provides that "[a]n enterprise shall initially recognize the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination."[76] Kentucky-American notes that its experience is common among many utilities and that many of these utilities have taken the same action as Kentucky-American.[77] The FIN 48 liability reduces Kentucky-American's deferred tax liability and thus increases Kentucky-American's rate base.[78]

Kentucky-American began booking the FIN 48 liability in 2009. As of the end of the forecasted test period, Kentucky-American will have booked $3,922,247 to this liability account.[79]

---

[75] Price Waterhouse Coopers, *Kentucky-American Water Co. Financial Statements as of and for the years ended December 31, 2008 and December 31, 2009* (Mar. 25, 2010) at 17 - 18, available at Case No. 2010-00036, Kentucky-American's Response to the AG's Second Request for Information, Item 85 at 20-21 (filed May 24, 2010).

[76] FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (June 2006) ¶ 6.

[77] VR 06/04/2013; 16:18:30 - 16:18:50.

[78] *Id.* Item 13(b). AG Witness Stephen M. Rackers testified that the FIN 48 account increases Kentucky-American's revenue requirement by approximately $400,000. Direct Testimony of Stephen M. Rackers at 2.

[79] Kentucky-American's Response to AG's Second Request for Information, Item 13(a). For a year-by-year listing of Kentucky-American's FIN 48 liability level, see Kentucky-American's Responses to Hearing Data Requests, Item 11 (filed June 20, 2013).

This case is not the first occasion in which the Commission has examined the reasonableness of Kentucky-American's establishment of the FIN 48 liability account. In Case No. 2010-00036 in which we approved Kentucky-American's accounting treatment, we stated:

> Kentucky-American determined that some uncertainty exists regarding the legality of the deduction related to the change in accounting methods. No party challenges the reasonableness of this determination or the appropriateness of establishing a reserve in the event of an adverse IRS ruling. Kentucky-American's action, moreover, is consistent with FIN 48. If the IRS ultimately allows the deduction or the statute of limitations expires without a challenge to the deduction, ratepayers and shareholders will benefit from the tax deferral. If the IRS disallows Kentucky-American's deduction, Kentucky-American has stated that it will not seek recovery for interest and penalties imposed by the IRS and the ratepayers will not be negatively affected.[80]

In the same Order, we rejected the AG's proposals that the Commission (1) increase Kentucky-American's accumulated deferred income taxes by the FIN 48 liability and recognize the benefit with an interest amount for the FIN 48 reserve that is recorded above the line; or (2) require Kentucky-American to record the interest below the line in tandem with the creation of a regulatory asset.

In the present proceeding, the AG urges the Commission to reconsider that decision. AG Witness Rackers recommends that Kentucky-American's accumulated deferred income taxes be increased by the FIN 48 liability and, should Kentucky-American receive an adverse ruling from the IRS, it be permitted to recover any interest payments from ratepayers.[81] In the alternative, he recommends that the FIN 48 liability be excluded from accumulated deferred income tax, that the future potential annual

---

[80] Case No. 2010-00036, Order of Dec. 14, 2010 at 20.

[81] Testimony of Stephen M. Rackers at 6.

interest cost associated with the FIN 48 reserves be included in the cost of service in this case, and that a true-up and any recovery or refund of interest costs be performed in subsequent rate case proceeding.[82]

Our review of the record does not indicate any significant change since our decision in Case No. 2010-00036. The IRS has yet to provide definitive guidance, and therefore, the uncertainty related to the deductions still exists. No party in this proceeding has challenged the reasonableness of the establishment of the FIN 48 reserve.[83] Ratepayers will benefit if the IRS allows the deductions or the statute of limitations expires. Kentucky-American continues to represent that it will not seek rate recovery of the interest from its ratepayers if the IRS disallows a portion of the deduction.[84] The AG has offered no new argument or reasoning to support of his position.

Given the lack of any significant change and the absence of any new argument in this matter, we decline to depart from the position that we established in Case No. 2010-00036 and we find that accumulated deferred income taxes should be $57,007,044.

Deferred Debits. In its application, Kentucky-American requests that rate base be increased by $1,536,404 to include the unamortized balance of the deferred debits.[85] The Commission finds that this level is reasonable and should be allowed in rate base.

Other Rate Base Elements. In Case No. 2004-00103, the Commission reduced rate base for contract retentions, unclaimed extension deposit refunds, retirement work

---

[82] *Id.* at 7.

[83] *See, e.g.*, Testimony of Stephen M. Rackers at 4.

[84] Kentucky-American Brief at 14.

[85] Application Ex. 37, Sch. B-1 at 2; Direct Testimony of Linda C. Bridwell at 30.

in progress, deferred compensation and accrued pensions.[86] Kentucky-American calculates a rate base increase of $650,081, consistent with the Commission's decision in that case. The Commission finds that Kentucky-American's calculation of other rate base elements is accurate and increases Kentucky-American's rate base by $650,081.

Summary. Based on the adjustments discussed above, the Commission has determined the company's net investment rate base to be as shown in Table I.

Table I

Rate Base Component	Application Forecasted 13-Month Average Rate Base	Commission's Adjustments	Commission Forecasted 13-Month Average Rate Base
Utility Plant at Original Cost	$ 627,540,378	$ 2,298,760	$ 629,839,138
Accumulated Depreciation	(136,601,885)	(31,332)	(136,633,217)
Net Utility Plant in Service	490,938,493	2,267,428	493,205,921
CWIP	6,851,268	(554,089)	6,297,179
Working Capital Allowance	3,946,000	(1,540,000)	2,406,000
Other Working Capital	727,081		727,081
CIAC	(52,238,690)	(813,001)	(53,051,691)
Customer Advances	(13,997,843)	(179,147)	(14,176,990)
Deferred Income Taxes	(57,007,044)	(446,815)	(57,453,859)
Deferred Investment Tax Credits	(55,276)		(55,276)
Deferred Maintenance	4,644,233		4,644,233
Deferred Debits	1,536,404		1,536,404
Other Rate Base Elements	650,081		650,081
Net Original Cost Rate Base	$ 385,994,707	$ (1,265,624)	$ 384,729,083

Income Statement

For the base period, Kentucky-American reports operating revenues and expenses of $87,282,760 and $60,961,773, respectively.[87] It proposes several adjustments to revenues and expenses to reflect the anticipated operating conditions during the forecasted period, resulting in forecasted operating revenues and expenses

[86] Case No. 2004-00103, Order of Feb. 28, 2005 at 38.

[87] Application Ex. 37, Sch. C-1.

of $84,157,833 and $59,977,919, respectively.[88] The Commission accepts Kentucky-American's forecasted operating revenues and expenses with the following exceptions:

Water Revenues. Kentucky-American proposes to decrease its base period water revenues of $84,830,506 by $2,998,368 to $81,832,138. Kentucky-American's billing analysis reflects the actual billing determinants for the base period. Kentucky-American has adjusted these determinants to include customer growth through the forecasted test year and adjusted residential, commercial and Other Public Authority classes for declining usage trends for the forecasted test year.[89]

- Change in Revenue Normalization Method. Kentucky-American proposes an adjustment to normalized usage for residential, commercial and Other Public Authority ("OPA") customers. It has modified the methodology that it previously used to calculate this adjustment. In prior cases, it used a statistical weather normalization model that was based upon actual and historical meteorological data and other known predictor variables to predict customer use or sales levels. In the present case, Kentucky-American has employed a usage-normalization approach.

Under the usage-normalization approach, Kentucky-American calculated customer base usage by reviewing monthly water sales during the winter months (December through April) for each year in the period from 2003 to 2012.[90] Due to the low amount of outdoor water usage in these months, Kentucky-American regards these months as reflecting base, non-discretionary usage.[91] Studying the usage in these

---

[88] *Id.*

[89] Testimony of Linda C. Bridwell at 7.

[90] *Id.* at 34.

[91] *Id.*

months, Kentucky-American Witness Linda Bridwell testified, allowed the utility to see the underlying trends in base usage.[92]

To calculate usage per customer, Kentucky-American performed a four-step calculation. First, it recorded monthly sales data and then divided monthly sales by the number of customers to yield an average usage per customer. Next, Kentucky-American calculated winter consumption for residential and OPA customers, expressed in gallons per customer per month, for each year during the period. For commercial customers, Kentucky-American made this calculation only for the period from 2008 to 2012. Next, Kentucky-American created a "best-fit" linear regression trend line using the ten-year winter usage data for residential and OPA customers and the five-year winter usage data for commercial customers. Finally, it calculated the portion of consumption that is constant throughout the year as opposed to the amount of increased usage that occurs during summer usage period. It added the ten-year average non-base usage to the base use trend to produce the total trend.[93]

Kentucky-American asserts that this methodology produces a "weather neutral" result. The methodology reflects the trend in base usage, which is relatively unaffected by weather. As to non-base usage, which is significantly affected by the weather, the methodology uses a ten-year average of summer usage, which "represents the 'most likely' outcome in a given year."[94]

Kentucky-American further asserts that its methodology is more indicative of the factors that affect water usage than an adjustment based solely on weather. It contends

---

[92] *Id.*

[93] *Id.* at 34-35.

[94] *Id.* at 36.

that the reduction in water usage universally is due to numerous factors, including conservation, the installation and use of more-efficient plumbing fixtures and appliances, and new plumbing requirements.

Based upon this analysis, Kentucky-American determined that residential usage per customer is declining at a rate of 780 gallons per customer per year, or 2.1 gallons per customer per day; that the commercial usage per customer is declining at a rate of 7,584 gallons per customer per year, or 20.8 gallons per customer per day, and that the other public authority usage per customer is declining at a rate of 49,344 gallons per customer per year, or 135.2 gallons per customer per day.[95] This declining usage is reflected in the adjustments that Kentucky-American had made to base period usage.

The AG opposes the change in methodology and takes issue with the contention that the new approach is more accurate or more reflective of Kentucky-American's customers' usage. He notes that during the course of several ratemaking proceedings that stretch back to the early 1990s, the Commission discussed, scrutinized, and adjusted Kentucky-American's weather normalization model before finally accepting it. He describes Kentucky-American's unilateral action to replace "the approved weather normalization process with a declining use factor" as "a rather large step backward."[96] Noting that the usage normalization approach is based upon AWWC's system usage patterns, the AG argues that the Commission has previously rejected such an approach to be insufficient and has sought an approach based upon the usage characteristics of Kentucky-American's service territory.[97]

---

[95] *Id.*

[96] AG Brief at 15.

[97] *Id.*

Using weather information from the National Oceanic and Atmospheric Administration and the Palmer Drought Severity Index, AG Witness Rackers recommended that 2012 residential customer average monthly usage of 4,580 gallons and 2012 commercial customer average monthly usage of 37,200 gallons be used to determine normalized revenue for the test period. Mr. Rackers contends that, as rainfall levels in 2012 were closer to normal levels, the 2012 usage is more indicative of these customers' usage.[98] He further recommended that, instead of calculating OPA usage based upon a monthly average of 212,400 gallons per OPA customer, as Kentucky-American proposes, 229,590 gallons per OPA customer should be used to calculate sales to that customer class.[99] In support of this recommendation, Mr. Rackers notes that Kentucky-American's usage amount was less than that the average OPA customer usage in 2011, a year in which the area experienced extreme rainfall amounts.

Based upon our review of the evidence, the Commission finds that Kentucky-American's proposed adjustment should be denied. We agree that Kentucky-American has failed to properly account for customer usage trends. Although we find support for Kentucky-American's contention that customer usage is declining, we find insufficient evidence to support the severe decline in usage that Kentucky-American claims. We are of the opinion that Kentucky-American's methodology does not adequately consider the effect of weather and that, especially as it relates to commercial customer usage, is not based upon a sufficient period of time to establish reliable usage trends. The Commission further finds that the usage amounts that AG Witness Rackers proposes

---

[98] Testimony of Stephen M. Rackers at 23.

[99] *Id.* at 24.

are reasonable and should be used to calculate the normalized forecasted usage for residential, commercial, and OPA customers.

- Customer Counts. AG Witness Rackers testified that Kentucky-American used incorrect customer counts in its calculation of revenues from Industrial Customers, OPA, and Other Wholesale Customers. Mr. Rackers stated that Kentucky-American erred in using 21 customers in its annualized calculations for the Industrial Customer classification and should have used 24 customers instead.[100] He further contended that Kentucky-American erred in using 531 OPA customers, not 533 that Kentucky-American used.[101] Finally, he contended that Kentucky-American incorrectly used 12 wholesale customers to calculate revenues from wholesale customers, instead of 13 customers.[102]

Kentucky-American disputes Mr. Rackers's contentions. As to the missing industrial customers, Kentucky-American reviewed the usage of the customers in the industrial customer class and found that three customers historically used little or no water.[103] As they had little or no usage, Kentucky-American removed these customers from its customer counts.

As to its count of wholesale customers, Kentucky-American asserts that the missing wholesale customer had limited water purchases during the period and its purchases were included in the purchases of the other 12 wholesale customers. In the forecasted period, Kentucky-American took into account the 12 forecasted purchasers In contrast, Mr. Rackers used the average yearly amount purchased for the 12

[100] *Id.* at 23.

[101] *Id.* at 24.

[102] *Id.*

[103] Rebuttal Testimony of Linda C. Bridwell at 6.

customers and multiplied this average yearly amount by his 13 customers. This action results in the overstatement of revenues for this customer classification.[104]

As to the OPA Customer classification, Kentucky-American stated that it recognized a sharp decline in the number of OPA customers and usage in the last five years and noted that some OPA customers are seasonal customers, causing a fluctuation in usage. Kentucky-American used a ten-year decline in usage per customer to project a more moderate decline and sought to remove the effects of seasonal fluctuation.[105]

Having reviewed the AG's proposed adjustments and finding that Kentucky-American's adjustments more accurately reflect customer count and usage than those that the AG proposes, the Commission denies the AG's proposed adjustments to Kentucky-American's customer counts.

– Imputed Billing Revenue from LFUCG. LFUCG proposes that the Commission impute to Kentucky-American approximately $1.6 million of annual revenue that it asserts Kentucky-American effectively surrendered by terminating its agreement to provide billing services for LFUCG on August 31, 2012.

LFUCG operates a sanitary sewer system that serves Fayette County. Prior to 1995, LFUCG performed its own billing and collection functions. In May 1995, it entered into an agreement with Kentucky-American for collection and billing services. Under this agreement, Kentucky-American billed for LFUCG sanitary sewer service and

[104] *Id.* at 7.

[105] *Id.*

remitted those receipts to LFUCG.[106] In October 1996, Kentucky-American agreed to provide billing services for LFUCG landfill fees.[107] In 2009, it further agreed to bill and collect LFUCG's water quality fees.[108] For the three-year period ending December 31, 2011, Kentucky-American's average annual revenue for these billing and collection services was $1,406,960.[109] On August 31, 2012, Kentucky-American ceased its provision of billing and collection services for LFUCG.[110]

LFUCG offers several reasons for its proposed adjustment. It suggests that Kentucky-American's decision was unreasonable, as termination of the billing contract resulted in the loss of $1.6 million of annual revenues and produced only $250,000 of annual savings. It further states that Kentucky-American's decision caused significant financial harm to LFUCG by requiring LFUCG to obtain the same services from another vendor at a much higher cost. Finally, it contends that Kentucky-American customers received no recognizable benefit from the termination of the billing agreement.

---

[106] Agreement between Lexington-Fayette Urban County Government and Kentucky American Water Company (May 22, 1995) *available at* http://www.psc.ky.gov/tariffs/Water/Districts,%20Associations,%20&%20Privately%20Owned/Kentucky-American%20Water%20Company/Contracts (last visited Oct. 24, 2013).

[107] Agreement between Lexington-Fayette Urban County Government and Kentucky American Water Company (Oct. 31, 1996), *available at* http://www.psc.ky.gov/tariffs/Water/Districts,%20Associations,%20&%20Privately%20Owned/Kentucky-American%20Water%20Company/Contracts/ (last visited Oct. 24, 2013).

[108] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 77 at 1143-1153.

[109] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 76. During this period, Kentucky-American also provided billing and collection services for the city of Sadieville, Treehaven Mobile Home Park, and Verna Hills Neighborhood Association. The average annual revenue from these services during the same period was $3,094.

[110] The 2009 Agreement provided that either party could terminate the agreement on 90 days' prior notice. On July 1, 2011, Kentucky-American informally notified LFUCG of its intent to terminate the agreement. On October 3, 2011, Kentucky-American provided formal notification of the termination of the agreement as of March 31, 2012. *See* Kentucky-American's Response to Commission Staff's Second Request for Information, Item 77 at 1141. At LFUCG's request, Kentucky-American continued providing billing services until August 31, 2012.

Kentucky-American offers several reasons in support of its decision to terminate the agreement. First, termination of the agreement results in annual savings of $254,625. These savings stem primarily from avoiding the need to customize the BT information systems to permit third-party billing services and from the elimination of an employee to handle third-party billing issues.[111] Second, as a result of the elimination of LFUCG charges from Kentucky-American bills, "a greater number of [Kentucky-American] customers are timely paying their bills."[112] Third, Kentucky-American bills are easier to understand, and less customer confusion occurs.[113] Finally, terminating the agreement eliminated the obscured price signals that customers were receiving regarding their efficiency levels. Kentucky-American argues that its inclusion of fees on water bills that are unrelated to water consumption, for example water quality management fee and landfill fee, prevents customers from properly gauging the benefits of Kentucky-American's water efficiency efforts.[114]

We question the appropriateness of LFUCG's proposed adjustment. The practical consequence of the proposed adjustment is to penalize Kentucky-American for not continuing its provision of billing services to LFUCG. The agreement, which LFUCG negotiated and executed, however, clearly allows Kentucky-American to terminate the provision of billing services upon 90 days' notice. LFUCG, furthermore, has provided no

---

[111] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 78.

[112] Rebuttal Testimony of Cheryl D. Norton at 5. Ms. Norton testified that, after Kentucky-American discontinued third-party billing, it saw a nearly 37 percent decline in the number of shut-offs and assessed 16 percent fewer late-payment fees than expected. *See also* Kentucky-American's Responses to Hearing Data Requests, Item 4.

[113] *Id.*

[114] *Id.* at 5-6.

support for the proposition that a public water utility has an obligation to provide auxiliary services outside its regulated utility functions to raise revenue for its utility operations. We were unable to find any legal precedent to support such obligation.

Similarly, the Commission is reluctant to afford significant weight to LFUCG's claims of financial harm. Each of the agreements between LFUCG and Kentucky-American regarding billing and collection services was for a specified term. While each agreement was renewable, each agreement also permitted either party to terminate the agreement upon timely notice. By executing these agreements, LFUCG clearly recognized and accepted the possibility that Kentucky-American might exercise its right to terminate the agreement. If LFUCG preferred a longer commitment, then it had the opportunity to negotiate a longer commitment and either chose not to do so or was unwilling to agree to a higher contract price for such commitment.

The Commission finds that the provision of third-party billing services may result in some customer confusion. Kentucky-American customer surveys indicate customer confusion over the services that Kentucky-American provides and its responsibility for the services for which it billed.[115] While Kentucky-American had no role in LFUCG's efforts to address Fayette County's water quality and waste management problems, its provision of billing services for such functions could easily create a contrary impression in the public's mind. The level of customer confusion and its effect on Kentucky-American, however, is difficult to quantify and to balance against the costs of terminating the billing services agreement.

The record provides a confusing picture of the benefits and costs from the termination of the billing services agreement. The termination reduces Kentucky-

[115] Kentucky-American's Response to Hearing Data Requests, Item 5.

American's revenues by $1,619,499,[116] but also reduces Kentucky-American's total revenue requirement by $254,625.[117] This reduction in revenue requirement, however, does not flow through to Kentucky-American's ratepayers. By Kentucky-American's own calculations, the monthly bill of an average Kentucky-American residential customer is $0.90 greater than if the Kentucky-American had continued providing billing services.[118]

This confusion is at least in part due to the lack of accurate cost allocation information. Despite performing third-party billing services for LFUCG since 1995, Kentucky-American has never conducted a thorough cost-of-service study to determine the cost to provide the billing services. It acknowledges the absence of a detailed cost tracking mechanism for the expenses associated with third-party billing services. While a Kentucky-American employee was tasked with managing third-party billing contracts, "other costs to manage third party billing would have been embedded within a variety of functions, including customer service center charges and information technology charges."[119] Rather than allocate the expenses related to the performance of third-party billing and then remove both the revenues and expenses associated from third-party billing for ratemaking purposes, Kentucky-American instead chose to treat its revenues

[116] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 78. VR 06/05/2013; 09:22:14 – 09:23:23.

[117] *Id.*

[118] With the exception of public fire hydrant customers, the average bill for each customer class was lower if Kentucky-American continued to provide the billing services. *See* Kentucky-American's Responses to Hearing Data Requests, Item 13.

[119] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 76.

from third-party billing services as "above the line" and thus avoided a more detailed and specific allocation of costs.[120]

Based upon our review of the record, we find insufficient evidence to support LFUCG's proposed adjustment to revenues. While the Commission is sympathetic to LFUCG's arguments, we lack the legal authority to prevent Kentucky-American from exercising its right under the billing agreements to exit the contract arrangement. We, therefore, deny the proposed adjustment.

Allowance for Funds Used During Construction ("AFUDC"). In its application, Kentucky-American proposes to increase forecasted operating revenues by $491,629[121] to include an allowance for AFUDC. In calculating this forecast, Kentucky-American uses the weighted cost of capital of 8.2 percent.[122] To reflect the effect of slippage on CWIP and the reduction of its requested weighted cost of capital to 8.12 percent,[123] Kentucky-American in its base period update decreased AFUDC by $50,888 to arrive at its revised level of $440,741.[124] Using the 13-month average CWIP available for AFUDC of $5,862,774[125] and the overall rate of return of 7.61 percent, the Commission calculates a forecasted level of AFUDC of $446,157. This action, coupled with

[120] Greater Cincinnati Water Works currently provides billing and collection services for LFUCG. LFUCG selected Greater Cincinnati Water Works after a five-month competitive selection process. Greater Cincinnati Water Works was the total least cost vendor. *See* LFUCG's Response to Kentucky-American's Request for Information, Item 1 (filed May 1, 2013). LFUCG pays $500,000 more to Cincinnati Water Works to provide the same services that Kentucky-American had previously provided. Direct Testimony of William O'Mara at 6. The increased cost for similar services raises questions about the cost allocation practices that Kentucky-American employed.

[121] Application Ex. 37, Sch. C-1.

[122] *Id.* Ex. 37 Sch. J-1.1/J-2.1.

[123] Base Period Update-Revised Ex. 37, Sch. J-1.1/J-2.1.

[124] *Id.* Sch. C-1.

[125] Kentucky-American's Response to Commission Staff's First Request for Information, Item 3(a), W/P-1 at 39; Kentucky-American's Response to Commission Staff's Second Request for Information, Item 41 at 131.

Kentucky-American's revisions, results in an increase to Kentucky-American's revised forecasted operating revenues of $5,416.[126]

Fuel and Power. Having accepted the AG's proposed adjustments to water sales, the Commission finds that a corresponding adjustment to fuel and power expense to reflect the costs incurred to produce the additional water sales is necessary. To properly reflect the impact the increase in water sales will have on forecasted expenses, the AG proposes to increase Kentucky-American's fuel and power forecast by $150,000.[127] To calculate his proposed adjustment, the AG developed a cost factor using Kentucky-American's water sales and electricity costs and applied this factor to his recommended water sales.[128] The Commission finds that fuel and power expense should be increased by $117,061[129] to reflect the effect the Commission adjustment to water sales will have on the fuel and power expense forecast.

Chemicals. A corresponding adjustment to chemical expense to reflect increased costs due to the Commission's adjustment to forecasted sales is also necessary. The AG proposes to increase chemical expense by $70,000.[130] To calculate his adjustment, the AG developed a chemical cost factor and applied this factor to his proposed increase to water sales.[131] The Commission finds the AG's

---

[126] $5,862,774 (13-Month Average CWIP Available for AFUDC) x 7.61% (Commission Weighted Cost of Capital) = $446,157.

[127] Direct Testimony of Stephen M. Rackers at 25.

[128] *Id.*

[129] $368,231 (Increase to Forecasted Water Sales) x $0.3179 (Fuel and Power Cost Factor) = $117,061.

[130] Direct Testimony of Stephen M. Rackers at 25.

[131] *Id.*

chemical cost factor is reasonable and has applied it to the increased level of water sales, which produces a chemical expense adjustment of $53,725.[132]

Pension. Kentucky-American records pension expense in accordance with FASB Accounting Standards Codification Topic 715 ("ASC 715"), formerly Statement of Financial Accounting Standards 87.[133] Kentucky-American proposes to decrease its base year pension expense of $1,025,878 by $42,671 to its forecasted level of $983,207.[134] Forecasted pension expense is based on an allocation of AWWC's 2013 and 2014 ASC 715 defined pension expense of $64,500,000 and $55,600,000 respectively. AWWC's monthly pension expense is calculated for the forecasted test year and a 1.99 percent allocation factor is used to arrive at Kentucky-American's gross pension expense of $1,180,236. Kentucky-American multiplies this amount by the reciprocal of its capitalization rate, or 83.31 percent[135] to arrive at its forecasted pension expense of $983,207.[136]

In its base period update, Kentucky-American proposes to decrease forecasted pension expense by $35,902 to reflect Towers Watson's most recent projections.[137] The Commission finds that the proposed adjustment to most current projections is reasonable and that Kentucky-American's forecasted pension expense should be decreased by $35,902 to a revised level of $947,305.

---

[132] 368,231 (Increase to Forecasted Water Sales) x $0.1459 (Chemical Cost Factor) = $53,725.

[133] Direct Testimony of Melissa L. Schwarzell at 14.

[134] Application Ex. 37, Sch. C-1; Direct Testimony of Melissa L. Schwarzell at 14.

[135] *Id.* at 11. $6,880,213 (Kentucky-American's Operation and Maintenance Labor) ÷ $8,258,965 (Kentucky-American's Total Gross Labor) = 83.31%.

[136] Direct Testimony of Melissa L. Schwarzell at 11.

[137] Base Period Update Filing-Summary of Forecast Year Revisions at 1; Rebuttal Testimony of Linda C. Bridwell at 4.

Group Insurance. Kentucky-American increased its base year group insurance expense of $1,964,516 by $144,987 to arrive at its forecast expense level of $2,109,504.[138] The forecasted expense comprises two components other post-retirement employee benefit costs ("OPEB"s) and Non-OPEB Group Insurances.[139]

Non-OPEB group insurances include: (1) basic life, short and long term disability, accidental death and disability; (2) voluntary employee beneficiary association ("VEBA"); and (3) health, dental, and vision coverages that Kentucky-American provides its employees.[140] The expense associated with the first category was calculated using the 2012 plan rates and a projected 8 percent premium increase in October 2013.[141] The second category, VEBA, "is a trust to help finance post-retirement benefits of non-pension-eligible employees" with a cost of $500 per non-union employees hired between January 1, 2006 and December 31, 2010.[142] The third category involves a gross Company cost net of employee contributions and is calculated on a position by position basis, according to each actual employee plan selection.[143] This category is based upon 2012 premiums with a projected 8 percent premium increase in October 2013.[144] Kentucky-American combines the three non-OPEB categories for each employee and multiplies each employee's total by each employee's reciprocal

---

[138] Kentucky-American's Response to Commission Staff's First Request for Information, Item 3(a), W/P-3 at 31.

[139] Direct Testimony of Melissa L. Schwarzell at 7.

[140] *Id.* at 7-8.

[141] *Id.* at 8.

[142] *Id.* at 9.

[143] *Id.*

[144] *Id.*

capitalization rate to arrive at the forecast non-OPEB group insurance costs of $1,418,443.[145]

Non-union employees hired before January 1, 2005 and union employees hired before January 1, 2010, are eligible for OPEBs upon their retirement, which includes Company sponsored medical, dental and prescription drug benefits.[146] To forecast test year OPEB cost, Kentucky-American starts with the latest estimates of AWWC's 2013 and 2014 post-retirement welfare costs, which are $33.3 million and $30.7 million, respectively.[147] AWWC's monthly OPEB expense is calculated for the forecast test year and a 2.61 percent allocation factor is used to arrive at Kentucky-American's gross OPEB expense of $829,455. Kentucky-American multiplies this amount by the capitalization rate of 83.31 percent to arrive at its forecasted OPEB expense of $691,061.[148]

After filing its application, Kentucky-American proposed to decrease forecasted OPEB expense by $48,149 to reflect Towers Watson's most recent projections and a further reduction of $8,783 to eliminate a duplicated cost.[149] The Commission finds that the proposed adjustments to reflect the most current projections and to eliminate duplicate costs are reasonable and that Kentucky-American's forecasted pension expense should be decreased by $56,932 to a revised level of $2,052,571.

Support Service Fees. American Water Works Service Company ("AWWSC") provides certain support services to Kentucky-American. These support services

---

[145] *Id.* at 9-10.

[146] *Id.* at 10.

[147] *Id.*

[148] *Id.*

[149] Rebuttal Testimony of Linda C. Bridwell at 4.

include the use of centralized call centers, water quality testing lab, information technology support, accounts payable and accounts receivable, tax support and insurance, as well as corporate governance.[150]

Kentucky-American has increased base period support service expense of $8,951,414 by $372,820 to its forecasted level of $9,324,234.[151] While Kentucky-American proposes to remove employee incentive compensation of $513,193 from its forecasted expense level,[152] its forecasted test period expense still exceeds base period expense level due primarily to two driving forces. First, labor and labor-related costs are forecasted to increase $382,055, due to merit pay increases in 2013 and 2014 and additional information technology support for BT efforts.[153] Second, maintenance and depreciation expenses are expected to increase by $415,023, due to the BT implementation and to efforts to continue the operations of the old financial systems.[154]

We note that in 2012, AWWSC revised its method for billing for Customer Service Center services. Prior to that year, AWWSC allocated most Customer Service Center costs to Kentucky-American based on the percentage of its customer count to the overall AWWC regulated utility customer count.[155] After it began tracking the calls by operating affiliate and the average call handling time, AWWSC found a

---

150 Direct Testimony of Linda C. Bridwell at 16.

151 Kentucky-American's Response to Commission Staff's First Request for Information, Item 3(a), W/P-3 at 85.

152 *Id;* Direct Testimony of Linda C. Bridwell at 16. In previous Kentucky-American rate case proceedings, the Commission had identified several concerns with Kentucky-American's employee incentive compensation plans and had not permitted recovery of such plans' costs to be recovered through rates. *See, e.g.,* Case No. 2010-00036, Order of Dec. 14, 2010 at 29-33.

153 *Id.* at 18.

154 *Id.* at 19.

155 Kentucky-American's Response to Hearing Data Requests, Item 30

disproportionate level of calls and call handling time by state.[156] In 2012 it began directly charging Customer Service Center calls based on the proportionate number of calls and average call handling time.[157]

Kentucky-American reports that presently approximately 63 percent of its call center costs are being direct charged for the amount of call handling, billing and collections costs it incurs at the Customer Service Center. The remaining 37 percent represents overhead components of Customer Service Center functions which are charged to Kentucky-American and its regulated utility affiliates based on the previous allocation method.[158] Based upon Kentucky-American's estimates, the change in methodology has increased the annual cost of the Kentucky-American's use of the Customer Service Center's services by $899,162.[159]

We find no basis to conclude that the change in AWWSC's billing is inconsistent with the provisions of the 1989 agreement between AWWSC and Kentucky-American. This agreement provides that directly billed costs are to be charge based on the employee's hours directly attributable to the affiliate "or other mutually acceptable means of determination."[160] It also provides that all costs incurred in connection with the services provided by AWWSC which can be identified and related to exclusively to

---

[156] Direct Testimony of Linda C. Bridwell at 17-18.

[157] *Id.* at 18.

[158] Kentucky-American's Response to Hearing Data Requests, Item 30.

[159] *Id.*

[160] Agreement between American Water Works Service Co. and Kentucky-American Water Co. (Jan. 1, 1989) ¶ 2.2.

Kentucky-American shall be charged to Kentucky-American.[161] AWWSC's new billing practice appears consistent with these provisions.

In summary, the Commission finds that Kentucky-American's forecasted support service fees of $9,324,323 is reasonable and should be accepted for ratemaking purposes.

Miscellaneous Expense. Kentucky-American includes miscellaneous expense of $1,170,548 in forecasted operations.[162] This expense includes, but is not limited to, the following: customer education items; community relations; company dues and memberships; director's fees; hiring costs; injuries and damages; lab supplies; and operating expenses. Kentucky-American has identified $150,250 of this expense as charitable donations that were inadvertently included in forecasted miscellaneous expense[163] and for which it has disclaimed any intent to seek rate recovery. In its base period update, it removed these donations from its forecasted miscellaneous expense.[164] Kentucky-American also removed $62,000 for a low income payment program, which is a form of charitable donation.[165] Kentucky-American's total adjustment to miscellaneous expenses to remove charitable donations is $212,250.[166]

As such donations are not essential to the provision of utility service, the Commission has generally found that charitable contributions should be borne by utility

---

[161] *Id.* at ¶ 2.3.

[162] Application Ex. 37, Sch. C-2.

[163] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 109.

[164] Base Period Update Filing-Ex. 37, Sch. C-2.

[165] Kentucky-American's Supplemental Response to Commission Staff's Second Request for Information, Item 109 (filed May 15, 2013).

[166] Rebuttal Testimony Linda C. Bridwell at 2.

shareholders.[167] Accordingly, we accept Kentucky-American's proposed reduction to its forecasted miscellaneous expense of $212,250.

Uncollectible Accounts. To calculate its forecasted uncollectible account expense, Kentucky-American applied the three-year average of its net charge-offs to billed revenue for the 12-month periods ending September 31, 2010, September 31, 2011, and September 31, 2012.[168] Kentucky-American applied that ratio to forecasted revenues at present rates to calculate its uncollectible expense forecast of $481,803.[169] By applying the Kentucky-American's uncollectible ratio to the Commission-adjusted increase in water sales, the Commission arrives at its uncollectible account expense adjustment of $10,457.[170]

Depreciation. Kentucky-American includes depreciation expense of $13,121,602 in its forecasted operations.[171] Based on the Commission's treatment of forecasted rate base with regard to slippage, an adjustment has been made to increase forecasted depreciation expense by $19,815.[172]

General Taxes. Kentucky-American includes a forecast of general tax expense of $5,114,771, which includes property taxes of $4,455,772, payroll taxes of $532,600,

[167] Case No. 10481, *Adjustment of Rates of Columbia Gas of Kentucky, Inc.* (Ky. PSC Oct. 6, 1989) at 22-23.

[168] Direct Testimony of Jermaine K. Bates at 3.

[169] *Id.*; Application Ex. 37, Sch. C at 2.

[170] $83,642,642 (Water Sales) + $1,834,066 (Other Operating Revenues) = $85,476,708.
$85,476,708 (Operating Revenues) x 0.5759% (Uncollectible Ratio) = $492,260.
$492,260 (PSC Uncollectible Account) - $481,803 (Utility Uncollectible Account) = $10,457.

[171] Application Ex. 37, Sch. C-1; Kentucky-American's Response to Commission Staff's First Request for Information, Item 3(a), W/P-4 at 2, 20. $11,517,623 (Depreciation) + $1,603,979 (Cost of Removal) = $13,121,602.

[172] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 41 at 84. $11,531,748 (Depreciation-Slippage Adjusted) + $1,609,669 (Removal-Slippage Adjusted) = $13,141,417 (Total-Slippage Adjusted). $13,141,417 - $13,121,602 = $19,815.

Public Service Commission assessment of $123,659, and taxes and licenses of $2,740.[173] The Commission finds that based on our treatment of forecasted rate base with regard to slippage, forecasted property tax expense should be increased by $8,730. We further find that the PSC assessment should be increased by $2,676 to reflect the effect of increased water sales. The total increased adjustment to Kentucky-American's forecasted general tax expense is $11,406.

Interest Synchronization. Kentucky-American proposes a forecasted interest expense of $12,481,618 based on the forecasted capital structure, the weighted cost of debt and the weighted dividend rate on the preferred stock.[174] As shown in Table II, the Commission has recalculated this expense to be $12,503,605 based on the rate base and weighted cost rates found reasonable herein.

Table II

	Weighted Cost Rates	Commission's Rate Base	Interest Synchronization
Short-Term Debt	0.0100%	384,729,083	$ 38,473
Long-Term Debt	3.1400%	384,729,083	12,080,493
Preferred Dividend	0.1000%	384,729,083	384,729
Interest Synchronization	3.15%	384,729,083	$ 12,503,695

Income Taxes. Kentucky-American includes a forecast of current income tax expense of $4,149,912, which includes state income taxes and federal income taxes of $491,702[175] and $3,658,210,[176] respectively. Adjusting Kentucky-American's income

[173] Kentucky-American's Response to Commission Staff's First Request for Information, Item 3(a), W/P-5 at 2.

[174] Application Ex. 37, Sch. E-1.3.

[175] Kentucky-American's Response to Commission Staff's First Request for Information, Item 3(a), W/P-6 at 5.

[176] *Id.* at 4

tax forecast, the Commission arrives at its current state income tax expense of $572,622 and federal income tax expense of $4,143,811 as shown in Table III.

Table III

	Income Taxes	
	State	Federal
Taxable Income - Forecast	$ 8,195,045	$ 10,452,028
Adjustments to Taxable Income:		
Water Sales	1,810,504	1,810,504
Fuel and Power	(117,061)	(117,061)
Chemicals	(53,725)	(53,725)
Pensions	35,902	35,902
Group Insurance	56,932	56,932
Miscellaneous Expenses	212,249	212,249
Uncollectible Accounts	(10,457)	(10,457)
Depreciation	(19,815)	(19,815)
General Taxes	(11,406)	(11,406)
State Income Taxes		(83,919)
Interest Synchronization	206,309	206,309
Temporary Differences - Slippage	(710,775)	(638,081)
Taxable Income - Commission	9,593,702	11,839,460
Multiplied by: Income Tax Rates	6%	35%
Income Taxes - Commission	$ 575,622	$ 4,143,811

Deferred Income Taxes. Kentucky-American includes a forecast of deferred income tax expense of $3,573,985, which includes state deferred income taxes and federal deferred income taxes of $674,791 and $2,899,194, respectively.[177] The Commission finds that, after adjusting Kentucky-American's income tax forecast for slippage, its forecasted deferred income tax expense should be of $4,078,706.

Summary. As shown in Table IV, the Commission finds that Kentucky-American's forecasted net operating income at present rates is $25,013,042.

[177] Application Ex. 37, Sch. E-1.3 and E-1.4.

Table IV

Account Titles		Application Forecasted Revenues and Expenses		Commission Adjustments		Commission Forecasted Revenues and Expenses
Operating Revenue:						
Water Sales	$	81,832,138	$	1,810,504	$	83,642,642
Other Operating Revenues		1,834,066		0		1,834,066
AFUDC		491,629		4,244		495,873
Total Operating Revenues		84,157,833		1,814,748		85,972,581
Operating Expenses:						
Operation and Maintenance Expenses		33,892,178		(123,840)		33,768,338
Depreciation		13,121,602		19,815		13,141,417
Amortization - UPAA		210,261		0		210,261
Current State Income Tax		491,702		83,919		575,621
Deferred State Income Tax		674,791		38,745		713,536
Current Federal Income Tax		3,658,210		485,601		4,143,811
Deferred Federal Income Tax		2,899,194		465,976		3,365,170
Investment Tax Credit		(84,792)		0		(84,792)
General Taxes		5,114,771		11,406		5,126,177
Total Operating Expenses		59,977,917		981,622		60,959,539
Net Income Available for Common	$	24,179,916	$	833,126	$	25,013,042

Rate of Return

Capital Structure. Kentucky-American's proposed capital structure, which is based on the projected 13-month average balances for the forecasted test period, and the costs assigned to each capital component are shown in Table V.

Table V

Kentucky-American's Application				
Components		Capitalization	Ratio	Assigned Returns
Short-Term Debt	$	7,845,933	2.041%	0.8100%
Long-Term Debt		200,086,655	52.037%	6.1400%
Preferred Stock		4,489,951	1.168%	8.5200%
Common Equity		172,085,833	44.754%	10.9000%
Total Capitalization	$	384,508,372	100.000%	

In its base year update, Kentucky-American revised its forecasted capital structure to reflect: (1) the delay of Kentucky-American's issuance of $8 million of long-term debt from November 2012 to May 15, 2013; (2) the delay of Kentucky-American's issuance of $3 million of long-term debt from May 2013 to November 2013; (3) revisions in interest rates and issuance costs for the projected long-term debt issuance in May 2013, November 2013, and May 2014; (4) revisions in Kentucky-American's projection for the cost of short-term debt; and (5) the weighted average cost of capital to reflect the effect of the other revisions.[178] Kentucky-American's revised forecasted capital structure and assigned cost rates are shown in Table VI.

Table VI

Kentucky-American's Update			
Components	Capitalization	Ratio	Assigned Returns
Short-Term Debt	$ 9,204,650	2.391%	0.5000%
Long-Term Debt	199,241,777	51.748%	6.0600%
Preferred Stock	4,489,938	1.166%	8.5200%
Common Equity	172,085,452	44.695%	10.9000%
Total Capitalization	$ 385,021,817	100.000%	

Although he did not object to Kentucky-American's capital structure, the AG used the capital structure that appears in Table VII to develop his recommended weighted cost-of-capital.[179]

[178] Rebuttal Testimony of Scott W. Rungren at 5.

[179] Direct Testimony of J. Randall Woolridge, Ex. JRW-1.

Table VII

AG's Capital Structure				
Components		Capitalization	Ratio	Assigned Returns
Short-Term Debt	$	7,845,926	2.040%	0.8100%
Long-Term Debt		200,086,674	52.040%	6.0500%
Preferred Stock		4,489,964	1.170%	8.5200%
Common Equity		172,085,807	44.750%	8.5000%
Total Capitalization	$	384,508,371	100.000%	

Upon review of the record, the Commission finds that Kentucky-American's revised capital structure accurately projects the test-year capitalization requirements, and should be used to develop the weighted cost-of-capital.

Short-Term and Long-Term Debt. Kentucky-American originally projected short-term and long-term interest rates of 0.81 percent and 6.14 percent, respectively.[180] In its base period update, Kentucky-American revised its original projections of short-term and long-term interest rates to 0.5 percent and 6.06 percent, respectively.[181] The AG proposed short-term and long-term interest rates of 0.5 percent and 6.05 percent, respectively.[182] Upon review of the supporting calculations, the Commission finds that Kentucky-American's revised projections result in a more current projection of the forecasted debt rates and that Kentucky-American's proposed cost of debt is reasonable and should be accepted.

[180] Application Ex. 37, Sch. J-1.1/J-2.1.

[181] Base Period Update Filing-Schedule J-1.1/J-2.1.

[182] Direct Testimony of J. Randall Woolridge at 16 - 17.

Preferred Stock. Kentucky-American proposed an embedded cost of preferred stock of 8.52 percent.[183] No party objected to this forecasted cost rate. We find that the proposed embedded cost of preferred stock is reasonable and should be accepted.

Return on Equity. Kentucky-American recommends a return on equity ("ROE") ranging from 10.4 percent to 11.4 percent and specifically requests an ROE of 10.9 percent based on its discounted cash flow model ("DCF"), the ex ante risk premium method, the ex post risk premium method, and Capital Asset Pricing Model ("CAPM").[184]

To perform its analysis, Kentucky-American Witness Vander Weide employed two comparable risk proxy groups in its analysis. The first proxy group consists of six water companies included in the *Value Line Investment Survey* ("*Value Line*") that: pay dividends; did not decrease dividends during any quarter for the past two years; have an analyst's long-term growth forecast; and are not part of an ongoing merger. All of these water companies have a *Value Line* Safety Rank of at 2 or 3, with 3 being the average of all *Value Line* companies.[185]

Dr. Vander Weide's second proxy group consisted of seven natural gas local distribution companies. Each company is in the natural gas distribution business; paid quarterly dividends over the last two years; had not decreased dividends over the last two years; was not involved in an ongoing merger; and had an available I/B/E/S long-

[183] Application Ex. 37, Sch. J-1.1/J-2.1.

[184] Direct Testimony of Gary M. VerDouw at 10; Direct Testimony of James H. Vander Weide at 3-4.

[185] Direct Testimony of James H. Vander Weide at 27.

term growth estimate.[186] Each also had a *Value Line* Safety Rank of 1, 2 or 3 and an investment grade bond rating.[187]

Dr. Vander Weide applied a quarterly DCF model to the water and gas proxy groups. He relied upon a comparable group of gas distribution utilities for the ex ante risk premium ROE estimation. He relied upon Standard & Poor's ("S&P") 500 stock portfolio and Moody's A-rated Utility Bonds to derive the ex post risk premium ROE estimation. He conducted a second study using stock data from the S&P Utilities rather than the S&P 500. Although Dr. Vander Weide performed CAPM analyses using both proxy groups, he did not rely upon the CAPM estimations in reaching his recommended ROE. He rejected the CAPM analyses because the average beta coefficient for the proxy companies was significantly below a value of 1 and because of the proxy group of water companies' small market capitalization.[188] As part of his ROE recommendations, Dr. Vander Weide also made adjustments for flotation costs.

AG Witness Woolridge takes issue with several aspects of Kentucky-American's methodology. First, he argues that Dr. Vander Weide's water proxy group is too small to estimate an equity cost rate and that Dr. Vander Weide erred in excluding the three smallest water companies from his proxy group. He also disagrees with the inclusion of NiSource in Dr. Vander Weide's gas proxy group due to its riskier operating and financial profile and its electric operations. Second, he states that Dr. Vander Weide's DCF approach included an excessive adjustment to the dividend yield to reflect

---

[186] *Id.* at 30. I/B/E/S, a division of Thomson Reuters, reports analysts' earnings per share ("EPS") growth forecasts for a broad group of companies. The I/B/E/S growth rates are widely circulated in the financial community, include the projections of reputable financial analysts who develop estimates of future EPS growth, are reported on a timely basis to investors, and are widely used by institutional and other investors. *Id.* at 22.

[187] *Id.* at 30.

[188] *Id* at 3 - 4, 45 - 48.

quarterly payment of dividends. Third, Dr. Woolridge asserts that the Kentucky-American study relies exclusively on the forecasted earnings per share ("EPS") growth rates of Wall Street analysts and *Value Line* to compute the equity cost rate, that the long-term earnings growth rates of Wall Street analysts are overly optimistic and upwardly-biased, and that the estimated long-term EPS growth rates of *Value Line* are overstated.

Fourth, Dr. Woolridge notes several problems associated with weighting the DCF results for the water and gas proxy groups by the market capitalization of the companies in computing the average DCF for each group. Fifth, he contends that both the risk premium and CAPM analyses performed by Kentucky-American contain excessive base interest rates and market risk premiums. Sixth, he observes that Dr. Vander Weide ignored his own CAPM equity cost rate results. Seventh, Dr. Woolridge states that flotation cost adjustments to the equity cost rate results are unwarranted.[189] Contending that the utility has failed to identify any actual floatation costs and questioning whether the necessary conditions that support the use of a floatation cost adjustment are present in the current case, Dr. Woolridge challenges the appropriateness of Dr. Vander Weide's use of floatation cost adjustment in his DCF analysis.[190]

Dr. Woolridge conducted his own analysis, applying the DCF model and the CAPM methods to a water proxy group and a gas proxy group and affording primary weight to the results of the DCF analysis. Based upon that analysis, he proposes an

---

[189] Direct Testimony of J. Randall Woodridge at 58.

[190] *Id.* at 68 - 70.

ROE range from 7.3 percent to 8.6 percent and recommends an awarded ROE of 8.5.[191]

To perform his analysis, Dr. Woolridge uses a proxy group of nine publicly-held water utility companies covered by *Value Line* and *AUS Utility Reports* and a second proxy group of nine natural gas distribution companies covered by the Standard Edition of *Value Line*. The water proxy group received 96 percent of its revenues from regulated water operations; has an 'A' bond rating and a common equity ratio of 46.5 percent; and an earned return on common equity of 9.8 percent. The gas proxy group consists of eight natural gas distribution companies listed as Natural Gas Distribution, Transmission, and/or Integrated Gas Companies in *AUS Utility Reports* and as Natural Gas Utility companies in the *Value Line* Standard Edition and having an investment grade bond rating by Moody's and S&P. The gas proxy group utilities received 69 percent of revenues from regulated gas operations, a common equity ratio of 47.7 percent, and an earned return on common equity of 10.5 percent.[192]

Dr. Woolridge argues that the use of natural gas distribution companies as a proxy for Kentucky-American is appropriate, since the financial data necessary to perform a DCF analysis on the members of the water proxy group, as well as analysts' coverage of water utilities, is limited. He also argues that the return requirements of gas companies and water companies should be similar, as both industries are capital intensive, heavily regulated, and provide essential commodity with rates and rates of return set by state regulatory commissions. Dr. Woolridge acknowledges, however, that

[191] *Id.* at 2.

[192] *Id.* at 14 - 15.

water companies do not face the same risk of substitution that exists for gas distribution companies.[193]

Dr. Woolridge places significant emphasis on current economic conditions and concluded that capital costs for utilities are historically low and are likely to be so for some time.[194] He further states that the investment risk of utilities is very low and that the cost of equity for utilities is among the lowest of all industries in the U.S. as measured by their betas.[195]

In his rebuttal testimony, Dr. Vander Weide addresses the criticism of his analysis and critiques Dr. Woolridge's analysis. Countering criticism of his proxy group selections, he notes that his proxy group of water utilities has a higher S&P bond rating and a slighter higher average *Value Line* safety than AWWC, and that his proxy group of natural gas utilities has a higher average *Value Line* safety rating and slightly higher average S&P bond rating than AWWC.[196]

Dr. Vander Weide rejects criticism of his use of a quarterly DCF model. He testifies that all companies within his proxy groups paid quarterly dividends and noted the same applied for those companies in Dr. Woolridge's proxy group. He further testifies that, as the DCF model is based on the assumption that a company's stock price is equal to the expected future dividends associated with investing in the

---

[193] *Id.* at 13 - 14.

[194] *Id.* at 12.

[195] *Id.* at 23 - 24.

[196] Rebuttal Testimony of James Vander Weide at 6 - 7.

company's stock, an annual DCF model cannot be based upon this assumption when dividends are paid quarterly.[197]

Dr. Vander Weide takes exception to Dr. Woolridge's internal growth method. He argues that this method is not only circular, but underestimates the expected growth of his proxy companies by neglecting the possibility that such companies can grow by issuing new equity at prices above book value. He notes that many of the proxy companies are currently engaging in this practice or are expected to do so in the future. This possibility is noteworthy, he asserts, because the water industry is expected to undertake substantial infrastructure investments in the near future and to finance those investments in part through this practice.[198]

As to his use of EPS growth rates in his DCF analysis, Dr. Vander Weide argues that his studies show that stock prices are more highly correlated with analysts' growth rates than with historical or internal growth rates that Dr. Woolridge considered. He states that, if Dr. Woolridge had used the average EPS share growth rates of Yahoo, Reuters, and Zacks in his DCF analysis, his DCF for the water utility proxy group would have been equal to 9.7 percent.[199] He further maintains that correctly using a full year of growth in the analysis would produce a 9.8 percent DCF result.[200] Dr. Vander Weide asserts that the proper application of the DCF model requires that matching of stock prices and investors' growth expectations. Moreover, he argues, historical growth rates are inherently inferior to analysts' forecasts because analysts' forecasts already incorporate all relevant information regarding historical growth rates and also

---

[197] *Id.* at 8 - 9.

[198] *Id.* at 11 - 12.

[199] According to Dr. Vander Weide, this result occurs even if a 1/2 g multiplier is used. *Id.* at 13.

[200] *Id.*

incorporate the analysts' knowledge about current conditions and expectations regarding the future. He refers to financial research that strongly supports the conclusion that analysts' growth forecasts are the best proxies for investor growth expectations.[201] Dr. Vander Weide concludes his discussion of the use of analysts' growth forecasts with his findings that analysts' EPS growth forecasts are not optimistic and that they are reasonable proxies for investor growth expectations, while Dr. Woolridge's historical and retention growth rates are not.[202]

Based upon our review of the record, we find that Kentucky-American's proposed ROE should be denied and that an ROE of 9.7 percent will continue to provide Kentucky-American with a fair and reasonable rate of return. In reaching our finding, we have focused upon the water utilities within the proposed proxy group. In Case No. 2010-00036, we found that Kentucky-American's use of natural gas distribution companies as proxies for water utilities to be inappropriate.[203] The water utility group consists of large and small publicly traded water utilities. While Kentucky-American is a relatively small water utility, it is part of a large, multi-state operation that has access to investment capital under conditions that few small water utilities could obtain. Accordingly, we are of the opinion that a proxy group consisting of water utilities is a more accurate indicator of risk and market expectations.

Our finding as to an ROE of 9.7 percent also continues to reflect Kentucky-American's regulatory history, with Kentucky-American's frequency of rate case

[201] *Id.* at 21.

[202] *Id.* at 25.

[203] Case No. 2010-00036, Order of Dec. 14, 2010 at 70 ("[S]everal of the companies within the natural gas proxy group that Kentucky-American has used engage in exploration, production, transmission, and other non-regulated and non-distribution activities. These activities extend well beyond a distribution function and have greater risk.").

applications since 1992 clearly demonstrating management's focused efforts to minimize regulatory risk and the risk associated with the recovery of capital investments. Kentucky-American has applied for rate adjustments on a more frequent basis than other water utilities within the proxy group, using a forecasted test period with each rate application. Not only does the ability to use a forecasted test period tend to reduce the risk associated with the recovery of capital investments, it is also a mechanism that is unavailable to several of the utilities in Kentucky-American's proxy group and their subsidiaries.[204]

In reaching our finding, we have also excluded any flotation cost adjustment from our analysis and have placed much greater emphasis on the DCF and the CAPM model results of the water utility proxy groups compiled by Kentucky-American and the AG. While recognizing that historic data has some value for use in obtaining estimates, we have given considerable weight to analysts' projections regarding future growth. Finally, in assessing market expectations, we have given considerable weight to present economic conditions.

Weighted Cost of Capital. As shown in Table VIII, applying the rates of 6.06 percent for long-term debt, 8.52 percent for preferred stock, 0.5 percent for short-term debt, and 9.70 percent for common equity to the adjusted capital structure produces an overall cost of capital of 7.59 percent. We find this cost to be reasonable.

---

[204] *See* Kentucky-American's Response to Commission Staff's Second Request for Information, Item 23 at 2.

Table VIII

Component	Capital Structure	Capital Ratios	Commision Returns	Commission Average Weighted Cost
Short-Term Debt	$ 9,204,650	2.391%	0.5000%	0.01%
Long-Term Debt	199,241,777	51.748%	6.0600%	3.140%
Preferred Stock	4,489,938	1.166%	8.5200%	0.10%
Common Equity	172,085,452	44.695%	9.7000%	4.34%
Total Capitalization	$ 385,021,817	100.000%		7.5900%

Authorized Increase

The Commission finds that Kentucky-American's net operating income for rate-making purposes is $29,200,937. We further find that this level of net operating income requires an increase in forecasted present rate revenues of $6,904,134.[205]

Cost of Service Study/Rate Design

For general water service, Kentucky-American currently charges a monthly service charge and a flat volumetric fee. The service charge is based in part on the customer's meter size. It is intended to recover the cost of customer facilities such as meters and services, and the cost of customer accounting, including billing and collecting and meter reading. The volumetric fee is intended to recover the cost of producing, transporting, and distributing the water.

Kentucky-American included with its application a cost-of-service allocation study that uses the base-extra capacity method.[206] This methodology is widely recognized

[205]

Net Investment Rate Base	$ 384,729,083
Multiplied by: Rate of Return	x 7.5900%
Operating Income Requirement	$ 29,200,937
Less: Forecasted Net Operating Income	- 25,013,042
Operating Income Deficiency	$ 4,187,895
Multiplied by: Revenue Conversion Factor	x 1.64859300
Increase in Revenue Requirement	$ 6,904,134

[206] Application Ex. 36.

within the water industry as an acceptable methodology for allocating costs.[207] This Commission has previously accepted the use of this methodology for cost allocation and development of water service rates.[208] No party has objected to the findings of the cost-of-service study.

In developing its proposed rates, Kentucky-American chose not to implement fully the cost-of-service study's results. According to the study, Kentucky-American should assess a monthly service charge of $14.86 per month for 5/8-inch meters.[209] Monthly service charges for the larger-sized meters are established by multiplying the meter capacity ratios by the 5/8-inch monthly service charge.[210] Kentucky-American proposes a monthly service charge for 5/8-inch meters of $14.00. While the proposed charge does not completely recover customer costs, it recovers a greater percentage of customer costs than the present customer charge and moves the utility closer to - completely cost-based rates.[211]

CAC proposes a tiered rate design in which the first usage block is charged a lower rate and the remaining usage blocks are charged an increasing amount.[212] It contends that this rate design would benefit all customers, not only those on low or fixed

---

[207] American Water Works Association, *Principles of Water Rates, Fees and Charges* (5th Ed. 2000) at 50.

[208] *See, e.g.*, Case No. 2002-00040, *An Investigation Into Butler County Water System, Inc.'s Rate Schedule for Services with Private Fire Protection Facilities* (Ky. PSC Mar. 29, 2005) at 12 ("While several different methods of allocating costs exist, the base-extra capacity method is one of the most widely used methods of allocating costs. It recognizes that the cost of serving customers depends not only on the total volume of water used but also on the rate of use. We have used this methodology in several rate proceedings and have found it an effective methodology.").

[209] Gannett Fleming, Inc., *Cost of Service Allocation Study as of July 31, 2014 and Proposed Customer Rates* (Harrisburg, Pa. Dec. 21, 2012) at 41.

[210] Direct Testimony of Paul R. Herbert at 10.

[211] *Id.* at 9.

[212] Direct Testimony of Jack E. Burch at 13.

incomes. Under this proposal, the initial block's volume would be equal to the minimum amount of life-sustaining water for household needs. The rate for the initial block would be at a free or substantially reduced rate. The rate for remaining usage blocks would progressively increase to reflect the actual cost of water. CAC failed to define the "minimum amount of life-sustaining water for a household" or provide a methodology for making such determination. It also failed to provide any analysis or supporting authority for its assumption that a correlation exists between income levels and water use levels.

Kentucky-American opposes CAC's proposal. Kentucky-American Witness Herbert testified that the CAC rate structure was not cost-based,[213] would provide a subsidy to all customers, including those with higher income levels, and would thus place an increased burden on customers who cannot maintain their water usage within the initial block, such as customers with home gardens or large families.[214] To provide some rate relief to low-income customers, Mr. Herbert recommended that the Customer Charge be discounted to low-income customers, with any lost revenue recovered from the remaining residential customers through an increased customer charge.[215] He also noted that an increasing block rate structure, such as CAC proposes, is mainly found in areas where water supplies are limited or drought conditions frequently occur.[216]

While the Commission agrees with CAC's goal of maintaining or improving the affordability of water service, we find its proposed rate design is neither practical nor suited for a water utility in an area with a plentiful water supply. Moreover, while intended to assist low-income customers, it will negatively affect those low-income

[213] Rebuttal Testimony of Paul Herbert at 4.

[214] *Id.* at 5.

[215] *Id.*

[216] *Id.* at 5.

users who cannot reduce water consumption to the minimum block level. Given the prohibition against unreasonable preferences set forth in KRS 278.170 and the Commission's past rulings that customer income is not a reasonable classification,[217] the proposal for a discounted minimum charge for low-income customers is not currently a viable alternative.

The Commission has used Kentucky-American's cost-of-service study as a guide to develop the rates and charges set forth in the Appendix to this Order. We, however, have not strictly adhered to it, but have instead allocated some costs to volumetric rates rather than the monthly service charge to ensure that Kentucky-American's rates are equitable to all customer classes and send the appropriate price signal. We agree with AG/LFUCG Witness Brian Kalcic that a reduction in the volumetric rate would send the wrong pricing signal to Kentucky-American customers.[218] Recognizing that modifications to the Cost of Service Rates would require a reduction in volumetric rates, we find that maintaining those rates at existing levels is the more reasonable and prudent course of action.

General Water Rates

The rates and charges contained in the Appendix to this Order produce the required revenue requirement based upon the revised forecasted sales. For a residential customer who uses an average of 5,000 gallons per month, these rates will increase his or her monthly bill from $35.40 to $38.95, or approximately 10.03 percent.

[217] *See, e.g.*, Case No. 2004-00103, Order of Feb. 28, 2005 at 80 - 83.

[218] Direct Testimony of Brian Kalcic at 11 ("a reduction in consumption charges would signal GMS customers that KAW's costs of supplying, treating and delivering 1,000 gallons of water are declining at a time when the Company claims such costs are increasing.").

Under Kentucky-American's proposed rates, the same customer would have seen his or her monthly bill increase 16.47 percent to $41.23.

Other Issues

Distribution System Improvement Charge. Kentucky-American proposes to implement a Distribution System Improvement Charge ("DSIC") to permit it to "accelerate the replacement of its aging infrastructure."[219] The DSIC is intended to encourage increased stockholder investment by eliminating the regulatory lag between the time when Kentucky-American makes an investment in plant and when it recovers the carrying cost in rates. Kentucky-American argues that the regulatory lag between investment and recovery in rates limits the amount of capital the stockholders are willing to make available to fund plant replacement.

The proposed DSIC would allow recovery through a separate billed charge of the cost of capital, depreciation, and property tax associated with qualified investment between rate case proceedings. The investment must be on plant that is non-revenue producing and was not included in rate base in a prior base rate case. The DSIC charge would be established on an annual basis using a 13-month average end-of-month UPIS balances and would reflect qualified plant additions constructed after the conclusion of the forecasted test year in the previous rate case. Qualified UPIS additions would be reduced by the projected UPIS retirements associated with the DSIC additions when calculating depreciation and property tax expense.[220]

An application for a DSIC would be filed 90 days prior to the effective date of each DSIC implementation. Each DSIC would include an annual reconciliation filing

[219] Testimony of Gary M. Verdouw at 17.

[220] *Id.* at 22.

made not later than 60 days after the conclusion of each DSIC year. Each filing would contain a detailed listing of each qualifying DSIC project completed and placed in service during the immediate preceding year. The filing is subject to Commission review and adjustment. The DSIC would be cumulative and would re-established at zero at the conclusion of the next base rate proceeding at which time the DSIC costs would be included in base rates. The DSIC would be capped at 10 percent of the authorized revenue level established in Kentucky-American's most recent rate proceeding.[221]

Kentucky-American argues that a pressing need exists to replace the distribution infrastructure that has exceeded its life expectancy. It argues that the reliability of its service is dependent upon its ability to replace aging distribution infrastructure.[222] It further states that implementation of the DSIC will permit it to focus upon replacement of mains that are six inches or less in diameter. These mains, it argues, are responsible for the majority of the distribution system leaks and failures.[223]

Kentucky-American contends that the DSIC "has a host of attendant customer protection measures that dispel any suggestion that KAWC is seeking to push through costs without sufficient regulatory oversight."[224] It further contends that the DSIC is a well-accepted regulatory mechanism that has been used in several states to address

---

[221] *Id. at 23.* In this case the proposed DSIC would be limited to $9,393,361 [$12,068,431(Kentucky-American's Revised Increase) + $81,865,176 (Revised Revenue from Water Sales) x 10%].

[222] *Id.* at 16.

[223] *Id.* at 19.

[224] Kentucky-American Brief at 24.

defined and significant infrastructure deficiency.[225] It compares the DSIC to the accelerated main replacement programs and gas line trackers the Commission has approved for other utilities.[226]

Kentucky-American explains that currently 82 miles of its six-inch or smaller water mains are 75 years old or older.[227] At the current annual investment rate of $3 million to $5 million, it will take approximately 41 years to replace the identified mains.[228] At the conclusion of this period, there will be an additional 947.77 miles of six-inch or smaller main with lives of greater than 75 years.[229] If a DSIC is approved, Kentucky-American intends to increase the capital available for the main replacement to a range of $5 million to $7 million, which Kentucky-American expects will shorten the replacement period to 16 to 27 years.[230]

The AG opposes the proposed DSIC tariff rider. He contends that the DSIC is ill-advised and unnecessary. The AG argues that Kentucky-American wants a solution for something that is not actually a problem.[231] Noting that since 1992 Kentucky-American has submitted a rate case with a forecasted test period every two years, the AG contends that the frequency of Kentucky-American's rate case applications "demonstrates management's focused efforts to minimize regulatory risk and the risk

---

[225] Testimony of Gary M. Verdouw at 20 – 21.

[226] Kentucky-American Brief at 117.

[227] Direct Testimony of Lance Williams at 15.

[228] *Id.*

[229] *Id.*

[230] Kentucky-American Response to the Commission Staff's Second Information Request, Item 50.

[231] AG Brief at 8.

associated with the recovery of capital investments."[232] According to the AG, the DSIC offers no material, incremental benefit, and that its approval would throw aside twenty years of effective regulatory oversight.[233]

He points to Kentucky-American's admission that there is no certainty that the DSIC tariff rider will reduce the frequency of base rate filings or that it will result in any short-term savings in operation and maintenance expenses.[234] The AG further argues that Kentucky-American has not identified the specific projects that will be recovered through the DSIC, nor does it have written procedures or policies to rank or prioritize the replacement of aging mains.[235] The AG argues that the DSIC "stands to reverse all of the gains made during the last twenty years in KAWC's capital budgeting and construction practices."[236]

Kentucky-American counters that it has provided details of its infrastructure planning process, identified the amount of its system that has exceeded its useful life, provided its current replacement rates, and identified the number of years it will take to replace 6 inch and less mains that have been in service longer than 75 years.[237] Kentucky-American asserts that it has shown that the replacement rate for its system mains is inadequate and must be accelerated if the problem is to be addressed in a timely fashion.[238]

---

[232] *Id.* at 7 - 8.

[233] *Id.* at 8.

[234] Direct Testimony of Stephen M. Rackers at 10.

[235] *Id.* at 8

[236] *Id.*

[237] Kentucky-American Brief at 26.

[238] *Id.*

Kentucky-American argues that the primary purpose of the DSIC tariff rider "is not to produce cost savings or delay rate cases, but to accelerate the needed remediation of aging water utility infrastructure on a proactive and sustained basis."[239] Incident to achieving this goal, are long-term cost reductions that may occur through reduced energy usage, pumping costs, reductions in unaccounted for water loss, reduced main breaks, and fewer customer calls about service interruptions.[240] Kentucky-American contends that its ratepayers will benefit from any of these cost reductions in the long term, and that the DSIC "will permit the Company to reduce the frequency of base rate cases."[241] These benefits are secondary to the principal benefit of Kentucky-American's DSIC.[242]

Kentucky-American is currently investing between $3 million to $5 million annually to replace its six-inch or smaller mains that have been in service 75 years or longer. Kentucky-American estimates that at this rate of investment, it will take 41 years to replace the identified mains. If it is granted a DSIC tariff rider, Kentucky-American will increase its annual investment to a range of $5 million to $7 million and estimates that it will take between 16 and 27 years to replace the mains. The annual replacement rate will increase from the current rate of two miles per year to a range of three miles to five miles.

Based upon our review of the evidence, the Commission finds that the proposed DSIC tariff should be denied. Given the minimal impact of Kentucky-American's increased investment on main replacement, the Commission is of the opinion that the

---

239 *Id.*at 27.

240 *Id.*

241 *Id.*

242 *Id.*

effect of the DSIC tariff rider will be marginal. If Kentucky-American continues its current course of submitting rate cases approximately every two years, then its estimated impact of the accelerated replacement of the mains has been overstated. Further, Kentucky-American contradicts itself when it states that mains with a diameter of six inches or less are responsible for the majority of the distribution system leaks and failures,[243] but then claims that DSIC tariff rider will not result in any identifiable cost savings in the near term. Unlike the DSIC tariff rider, the accelerated gas main tariff riders were allowed for safety concerns and the main replacements were for a defined accelerated replacement period.

Purchased Power and Chemical Charge. Kentucky-American proposes to establish a Purchased Power and Chemical Charge ("PPACC") to reflect the incremental changes in purchased power and purchased chemical costs from the level authorized for recovery in a base rate case proceeding.[244] The PPACC would have the following features:

- In a base rate case proceeding, the Commission would establish the appropriate level of purchased power and chemical expenses to be included in base rates.
- Each month this base cost, which is established on a per unit basis (1,000 gallons of water), would be compared to current month actual purchased power and chemical costs.
- Annually, Kentucky-American would file with the Commission a report of its actual purchased power and chemical costs, as well as the reconciliation of any prior period PPACC Rider over or under-recoveries.
- The PPACC would be determined by dividing the cumulative annual incremental increase or decrease in purchased

[243] Rebuttal Testimony of Scott W. Rungren at 10.

[244] Direct Testimony of Gary M. Verdouw at 28; Application Ex. 2 at 23.

power and chemical costs, grossed-up for the associated impact of revenue taxes, by projected annual base rate revenue subject to the PPACC Rider.

- The PPACC Rider would be expressed as a percentage and would be applied to the amount billed to each customer. The PPACC Rider amount would be reflected as a separate line item on the bill of each customer.

- The PPACC Rider would be subject to an annual reconciliation to determine the amount of any prior period PPACC Rider over or under-recovery which amount would be deferred and included in the Company's next PPACC for return to or recovery from customers.[245]

Kentucky-American contends that the PPACC is necessary to address the unpredictability and lack of control over purchased power and chemical expenses.[246] It maintains that the combined cost of purchased power and chemicals is the largest non-labor related component of its operations and maintenance expenses[247] and that the cost of purchasing these commodities is generally beyond Kentucky-American's control and their pricing can be volatile.[248]

Kentucky-American's forecasted chemical expense accounts for 5.3 percent of its total forecasted operation and maintenance expenses and 1.85 percent of its total revised revenue requirement.[249] Purchased power expense accounts for 11.22 percent

[245] Direct Testimony of Gary M. Verdouw at 31 – 31.

[246] *Id.* at 29 – 30.

[247] *Id.* at 30.

[248] *Id.* at 31.

[249] Base Period Update-Ex. 37 Sch. A and Sch. C-1. $1,779,872 (Chemical Expense Forecast) ÷ $33,587,569 (Total Operation and Maintenance Expense Forecast) = 5.3%. $1,779,872 (Chemical Expense Forecast) ÷ $96,208,414 (Revenue Requirement Revised Forecast) = 1.85%. *See also* Kentucky-American's Response to Hearing Data Requests, Item 31 ("chemical expense comprises 5.24% of Kentucky American's total operations and maintenance expenses from the Cost of Service Study ("COSS") and 2.16% of the Total Cost of Service").

of Kentucky-American's total operation and maintenance expenses and 3.92 percent of its total revised revenue requirement.[250]

The AG argues that these expenses do not, separately or combined, warrant deviation from traditional rate-making methodologies.[251] AG Witness Rackers testified that the use of PPACC effectively allows Kentucky-American to engage in single issue ratemaking. He contends that it allows Kentucky-American to receive additional revenue in rates due to an increase in a tracked expense or decrease in tracked revenue without any consideration of whether it would simultaneously be receiving offsetting decreases in expenses or offsetting increases in revenues for those expenses and revenues that are not being tracked.[252]

The AG also asserts that, given Kentucky-American's frequent rate applications, no certain incremental benefit associated with the use of a tariff tracker mechanism exists. He further asserts that the PPACC tracker may actually add regulatory burden and unnecessary complexity.[253] He warns that a tracker may serve as a disincentive for

---

[250] Base Period Update-Ex. 37 Sch. A and Sch. C-1. $3,768,292 (Fuel and Power Expense Forecast) ÷ $33,587,569 (Total Operation and Maintenance Expense Forecast) = 11.22%. $3,768,292 (Fuel and Power Expense Forecast) ÷ $96,208,414 (Revenue Requirement Revised Forecast) = 3.92%. *See also* Kentucky-American's Response to Hearing Data Requests, Item 31 ("The purchased power expense comprises 9.16% of total operations and maintenance expenses, and 4.58% of Total Cost of Service.").

[251] AG Brief at 19 - 20.

[252] Direct Testimony of Stephen M. Rackers at 20.

[253] AG Brief at 20.

Kentucky-American to control or to minimize its expenses.[254] The AG concludes that, if Kentucky-American needs a deviation, then the deferred debit methodology is better-suited for this application.[255]

Based upon our review of the record, we find that the proposed PPACC tariff rider should be denied. We do not agree with the premise that chemical and purchased power are totally outside of utility control. A utility may enter into long-term contracts for the purchase of chemicals. It may invest in energy-efficient equipment and take advantage of time-of-day rates to lessen its power costs. Moreover, if it is greatly concerned about its power costs, it can intervene in regulatory proceedings to zealously protect its interest when electric power rate adjustments are sought. As Kentucky-American concedes that its customers' water usage is decreasing, corresponding decreases in chemical and power purchases are also likely.

Finally, given that purchased power and chemical expenses account for a relatively small percentage of total utility expenses, the Commission finds no compelling need for the proposed tariff rider. For Kentucky-American, neither expense is at a level that is comparable to the level of purchased gas expense for a natural gas distribution

---

[254] AG Witness Rackers testified:

> [T]he use of a tracker eliminates the inherent incentive a utility has to minimize expenses and maximize revenues between base rate proceedings, which over time works to keep electric rates lower than they otherwise would be. When a utility is allowed to track an expense, it can become indifferent with regard to minimizing that expense since it knows it will not need to file a new base rate case in order to recover any increases in that expense. Similarly, when a utility is allowed to track a revenue, it can become indifferent with regard to maximizing that revenue since it knows that it will not need to file a base rate case in order to recover any shortfall in that revenue.

Direct Testimony of Stephen M. Rackers at 20.

[255] *Id.*

utility or purchased fuel expense for an electric utility. Other state commissions have reached the same conclusion.[256]

Tap Fees. Kentucky-American proposes to increase its tap fees based upon a five-year average of its actual cost of meter installation. Historically, Kentucky-American has used a three-year average to establish this fee, but since its last general rate adjustment application has used a five-year average. It has used the longer period to establish the fee due to the fewer number of connections caused by slower economic growth.[257] We find that the proposed tap fees will yield only enough revenue to pay the expenses incurred in rendering the service, are reasonable and should be approved.

Activation Fee. Kentucky-American proposes to increase its activation fee from $26 to $28. It has analyzed the costs incurred for service runs related to service activation, disconnection and reconnection. These analyses reflect that the current charge does not recover the full cost of the service activity. Ms. Bridwell testified that due to the utility's efforts in integrating technology and driving efficiencies, the costs of service trips have been very flat, but that the proposed adjustment is appropriate to bring the fee closer to the actual costs of providing the service.[258] We find that the proposed activation fee will yield only enough revenue to pay the expenses incurred in rendering the service, is reasonable, and should be approved.

Reconnection Fee. Kentucky-American proposes to increase its reconnection fee from $26 to $56. The proposed revision recognizes that the activity involved with a

---

[256] *See, e.g., Re West Virginia-American Water Co.*, 290 PUR4th 125 (W.Va. PSC Apr. 18, 2011) (rejecting a request to establish an investigation into the establishment of a purchased power adjustment clause because purchased power was not a dominant part of the water utility's cost of service).

[257] Direct Testimony of Lance Williams at 2-3.

[258] Direct Testimony of Linda C. Bridwell at 13-14.

reconnection involves two service trips to the customer's premises. The first trip is necessary to disconnect service. The second trip concerns the reconnection of service. In Case No. 2007-00143,[259] when Kentucky-American requested a reconnection fee of $26, it recognized that the fee would not provide for full recovery of the costs to provide the service.[260] The utility now wishes to obtain full recovery of these costs. We find that the proposed reconnection fee will yield only enough revenue to pay the expenses incurred in rendering the service, is reasonable, and should be approved.

Elimination of Afterhours Charges. Kentucky-American proposes to eliminate its Afterhours Activation or Reconnection Fees. As it has streamlined its organization, responsibility for after-hours service activations and reconnections has shifted to senior field services employees who work during the day. In recent years, Kentucky-American has encouraged customers to use after-hours activations or reconnections only on an emergency basis. This action has reduced overtime expense and also reduced the administrative work for Kentucky-American call representatives who processed the requests. In lieu of assessing the charges, Kentucky-American will continue to encourage its customers to use after-hours activations or reconnections only on an emergency basis.[261] No party opposes the proposal. We find that Kentucky-American's proposal is reasonable and should be approved.

Fire Hydrant Charge. Kentucky-American proposes to increase its monthly public fire hydrant charge from $37.84 to $45.30. Noting that the proposal will increase

[259] Case No. 2007-00143, *Adjustment of Rates of Kentucky-American Water Company* (Ky. PSC filed Apr. 30, 2007).

[260] Case No. 2007-00143, Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), W/P-2 at 89 (filed May 21, 2007).

[261] *Id.* at 15-16.

its cost by more than $600,000, LFUCG argues that such an increase to a single customer is "excessive and unjust and would result in rate shock to Lexington."[262] It further argues that principles of gradualism require a lower increase. While we differ with LFUCG on the definition of "rate shock" and gradualism, we find that, as a matter of fairness and equity, the increase in fees for private and public fire hydrants should be limited to the same percentage increase as the increase in the average residential customer's bill. This action will limit the increase in LFUCG's total cost for public fire hydrant rentals to approximately $300,000.

Unified Rate Structure/Surcharge for Northern Division Connection Project.

LFUCG states that none of the cost of the Northern Division Connection Project, which will permit Kentucky River Station II to serve as a water source for the Northern Division, should be assigned to Central Division customers. It argues that "the Company asks that the Central Division customers supplement the Northern Division while receiving no tangible benefit."[263] To permit Kentucky-American to recover the cost of the Northern Division Connection Project through rates and to accept LFUCG's position that no costs associated with the Project be recovered from Central Division customers is only possible if the present unified rate structure is abandoned or if a surcharge to recover the Project's costs is imposed solely on Northern Division customers.

Kentucky-American opposes the termination of its unified rate structure and the assessment of a surcharge. It argues that the Commission encouraged the use of a

[262] LFUCG's Brief at 5.

[263] LFUCG Brief at 8.

unified rate structure in Case No. 2005-00206,[264] approved such a pricing structure in Case No. 2007-00143, and has continued to approve such structure in subsequent rate case proceedings. It notes that LFUCG agreed to a unified rate structure in Case No. 2007-00143 as part of a settlement agreement. None of the parties objected to the continued use of a unified rate structure in Kentucky-American's next rate case proceeding.

Kentucky-American further advances the following arguments in support of the unified rate structure: (1) A unified rate structure spreads the cost of capital expenditures across a larger customer base, thereby decreasing the effect of a capital project on each customer; (2) It eliminates the administrative burden of maintaining multiple sets of books and records; (3) It creates economies of scale and maintains more affordable rates for customers by spreading costs over the entire base of customers; (4) It lowers administrative and regulatory costs; (5) It improves financial capital and capital deployment; (6) It achieves rate and revenue stability; and (7) It improves service affordability for very small systems.[265]

Kentucky-American states that its accounting system does not presently provide an accurate and precise allocation of costs between its two divisions and must be modified to permit the maintenance of separate cost records for the two divisions.[266] It asserts that establishing separate and distinct rate schedules for each division that

[264] Case No. 2005-00206, *Verified Joint Application of the City of Owenton and Kentucky-American Water Company for Approval of the Transfer of the Ownership of Water- and Wastewater-Related Assets of the City of Owenton to Kentucky-American Water Company* (Ky. PSC July 22, 2005).

[265] Kentucky-American Brief at 49; *see also* Janice A Beecher, Consolidated Water Rates: Issues and Practices in Single Tariff Pricing (Sept. 1999).

[266] Kentucky-American's Motion for Relief at 2 – 3 (filed Mar. 12, 2013).

accurately reflect the cost of service, therefore, would have to be deferred to Kentucky-American's next rate case proceeding.

As to the use of a surcharge on Northern District customers to recover the Northern Division Connector Project's costs, Kentucky-American argues that a surcharge conflicts with a unified rate structure and is generally inappropriate. It asserts that such a surcharge is contrary to water-industry practice that provides that surcharges should be used to recover costs arising from one-day events or emergencies.[267]

When questioned regarding the elimination of the uniform rate structure, the AG stated that he does not recommend any change to Kentucky-American's unified rate structure.[268] He also does not recommend the use of a surcharge on Northern Division customers to recover Northern Division Connection Project costs.[269]

Based upon our review of the record, we find that Kentucky-American's unified rate structure should remain in place. The Commission has consistently supported the concept of a unified rate structure to encourage consolidation of water systems and to improve the quality of water service in the Commonwealth. Reversal of this policy would discourage further water system consolidation.

Elimination of the unified rate structure is inconsistent with the integration of the Northern and Central Divisions. The two divisions have ceased to be separate water systems. With the construction of the Northern Division Connection Project, the divisions are interconnected and share the same water treatment source. Their

---

[267] *Id.* at 52.

[268] AG's Response to Commission Staff's Request for Information, Item 31.

[269] *Id.* Item 30.

administrative, engineering, purchasing and operation functions are merged. These events have rendered moot the questions about the use and appropriateness of a unified rate structure.

We further find that the assessment of a surcharge on Northern Division customers to recover the costs of the Northern Division Connection Project is unwise and unreasonable. It is contrary to the concept of single tariff pricing. As the Northern Division Connection Project will allow for further integration of the two divisions and create cost savings for both divisions through the increased and more efficient use of Kentucky River Station II, its costs should be borne by all Kentucky-American customers.

A separate surcharge, moreover, would likely create a significant hardship for Northern Division customers. If a surcharge on Northern District customers is used to recover the Northern Division Connection Project's costs, a monthly surcharge of $32 must be assessed on each Northern Division customer for the next 30 years. In contrast, recovery of these costs through general rates will result in an increase of approximately $0.84 to the average Kentucky-American residential customer's monthly bill. Under these circumstances, recovery of the costs through general rates is the more reasonable and preferable method and is consistent with our prior directives regarding the consolidation of Kentucky-American's rates.[270]

[270] *See* Case No. 2004-00103, Order of Feb. 28, 2005 at 75 – 76; Case No. 2005-00206, Order of July 22, 2005 at 6.

Future Water System Acquisitions

LFUCG cautions the Commission to pay close attention to the manner in which the costs of Kentucky-American's system expansions are recovered. It expresses the concern that the Central Division customer base may be used as a funding mechanism for future water system expansions[271]

Kentucky-American's Northern Division perfectly illustrates this concern. In this case, Kentucky-American acquired three small water systems that were experiencing significant operation problems and required infrastructure improvements. Given the small customer base of these acquired water systems, the only economically feasible means of financing these infrastructure improvements was to spread those costs over Kentucky-American's entire customer base. To finance the cost of the improvements only through rates assessed to the acquired systems' customers would have resulted in unaffordable rates for those customers. Instead, Kentucky-American recovered these costs from all of its customers, without regard to whether those customers directly benefited from the infrastructure improvements. Because these costs were spread over a much larger customer base, the increase in customer rates was relatively small.

This practice of cost sharing or cost spreading is not uncommon. For example, the cost of serving customers who are located closer to a water treatment plant is likely less than cost of serving customers who are located farther from treatment plant in the outer reaches of a water utility's service area. This Commission has recognized that differences in customer locations do not necessarily require different rates. The consolidation of costs in a unified pricing structure ensures affordable rates and high quality service for the greatest number of customers.

[271] LFUCG Brief at 8.

Kentucky-American's acquisition of small water systems that are in need of infrastructure improvement presents a critical question: What is the obligation of Kentucky-American's existing customers to finance system improvements to these acquired systems through higher rates for service? The answer depends upon the circumstances of each system acquisition. We recognize, however, that limits exist and that Kentucky-American's existing ratepayers should not be considered a deep pocket that is available in all cases to finance the improvements of acquired small water systems.

Our review of the record of Case No. 2005-00206 indicates this question was not considered. The Commission failed to thoroughly examine the possible consequences of Kentucky-American's acquisition of the Owenton Water System, including the cost of necessary infrastructure improvements and its potential effect on Kentucky-American's rates. As there was no specific statutory requirement for prior Commission review of Kentucky-American's acquisition,[272] the lack of review may be explainable. As the Commission in that proceeding also directed the use of a unified rate structure, the Commission should have at least posed the question.

The Commission finds that in the future a review of any acquisition of a water system by Kentucky-American should be conducted prior to the completion of that acquisition and that such review should address the question of the acquisition's potential effects on rates. In those instances in which Kentucky-American is acquiring a jurisdictional utility, KRS 278.020 currently requires prior Commission approval of the

[272] Case No. 2005-00206, Order of July 22, 2005 at 2 - 3 ("We find, however, no statutory requirement for such approval. KRS 278.020(5) and 278.020(6) require prior Commission approval of the transfer of control or ownership of any "utility." As a city, Owenton is not within the statutory definition of "utility." *See* KRS 278.010(3). KRS 278.020 therefore does not require Commission approval of the proposed transaction.")

acquisition. To meet its statutory obligation of demonstrating that the proposed acquisition is in the public interest, Kentucky-American will be expected to provide a detailed assessment of the costs of serving the acquired system and any necessary or expected service improvements, a plan for financing the cost of such improvements, an estimate of effect on the rates of acquiring system customers, and the benefits that existing system customers will accrue as a result of the acquisition.

As KRS 278.020 does not require Commission approval of Kentucky-American's acquisition of a non-jurisdictional water system, such as a municipal water utility, we nonetheless find that Kentucky-American should notify the Commission of its intent to acquire such systems at least 90 days prior to the proposed acquisition date. This notice will enable the Commission to conduct an inquiry or investigation into the proposed acquisition and its potential effects on existing system ratepayers.

We place Kentucky-American on notice that the consolidation of an acquired system's rates with Kentucky-American's rates should not be presumed. Kentucky-American must demonstrate the appropriateness and reasonableness of consolidating the rates. It should expect to maintain a separate set of records for acquired water systems for a reasonable period of time after the acquisition to enable the Commission to assess the cost of service for the acquired and acquiring systems and to better assist the Commission in determining the appropriateness and reasonableness of a unified/consolidated schedule of rates.

The position that we state today does not represent a departure from past Commission precedent. In Case No. 9283, we declared:

> The record in this case, in Case No. 9360, and in Case No. 9359 indicates that Kentucky-American intends to expand its service area outside the Urban County. The Commission

> commends Kentucky-American for pursuing the goal of serving as a regional water supplier. The Commission encourages Kentucky-American to pursue supply contracts with the adjacent districts as a way of using its excess treatment capacity and as an efficient method of providing basic water service within the region. But as a leader in Kentucky in the development of a regional water supply system, Kentucky-American must also look at the accompanying issues that this objective raises for the Commission. These issues include equity in cost allocation of treatment plant capacity and distribution capacity among service areas. The Commission is also concerned about the appropriate rate design for customer classes outside the Urban County. **Kentucky-American should be aware that the cost allocation and rate design method approved for the Urban County will not automatically be considered appropriate by the Commission for service to other counties.**[273]

Today, we merely affirm that position.

Service to Low-Income Customers

In Case No. 2010-00036, the Commission found that a collaborative effort should be undertaken to study potential regulatory and legislative solutions to the increasing lack of affordability of water service for low-income customers.[274] We directed Kentucky-American to initiate the process by arranging a meeting of the interested parties, to file periodic reports of the group's progress, and to submit a final report of the group's efforts no later than November 1, 2011.

CAC contends that Kentucky-American failed to comply with our directive. It asserts that no effort was undertaken by Kentucky-American to consider the comments and positions of other interested parties.[275] It further asserts that, even after legislation

---

[273] Case No. 9283, *Notice of Adjustment of the Rates of Kentucky-American Water Company* (Ky. PSC Oct. 1, 1985) at 14 (emphasis added).

[274] Case No. 2010-00036, Order of Dec. 14, 2010 at 75 – 76.

[275] CAC Brief at 9; VT 06/05/2013; 17:57:18 - 17:57:29.

was developed by the collaborative group, Kentucky-American failed to take the necessary efforts to garner support for the proposed legislation. It requests that Kentucky-American be directed to fund a study for solutions to the water-affordability problem in the Kentucky-American service area and that the Center on Poverty Research at the University of Kentucky conduct the study.

In a similar vein, the AG describes Kentucky-American's efforts as "feeble" and states that the Commission's "directions were not followed."[276] He rejects any suggestion that his office was an impediment to the group's work and states his willingness to work with Kentucky-American and other stakeholders on the issue of affordability.[277]

Kentucky-American insists that it has complied with the letter and the spirit of the Commission's directive. It organized the required meetings, filed required periodic reports, and timely submitted the required final report.[278] It notes that a legislative solution was developed, but that the other stakeholders failed to adequately support the agreed-upon solution. Kentucky-American insists that the most effective and most appropriate solution is a change in existing law to permit water utilities to use rate classifications based upon a customer's income level. It stated that it remained interested in enacting legislation to permit water utilities to assess a reduced meter charge to low-income customers.[279]

Based upon our review of the record, we find that Kentucky-American has complied with the letter of our Order, but not its spirit. For that matter, no collaborative

---

[276] AG Brief at 27.

[277] *Id.*

[278] Kentucky-American Brief at 59 – 60.

[279] *Id.* at 60 – 61.

member has fully complied with the spirit of Order. Notwithstanding their public posturing, collaborative members made little investment of time or effort in the process. No attempt was made to solicit potential stakeholders from outside this proceeding to expand the view, to explore administrative or ratemaking alternatives, or to seek the assistance of outside governmental or non-governmental organizations to examine the problem. When problems with the process arose, no collaborative member attempted to inform the Commission of the alleged problems or request our intervention. As a result, the collaborative has not met our expectations or produced any meaningful ideas.

While CAC's suggestion to involve the Center on Poverty Research has merit, this Commission lacks the authority to require Kentucky-American to expend its monies to fund an independent study on the issue and cannot grant CAC's requested relief. We find the parties' failure to seek out the Center on Poverty Research's assistance when the collaborative process began to be both unfortunate and indicative of the lack of imagination and initiative that they have displayed throughout the process.

The Commission finds that the collaborative should not continue in its present form. We will continue to evaluate possible forums for exploring this issue, either through a formal proceeding or through some informal process that may include the greater involvement of Commission's Staff. For the time being, however, we will not take any action to continue the collaborative process.

SUMMARY

After consideration of the evidence of record and being otherwise sufficiently advised, the Commission finds that:

1. Kentucky-American's proposed rates would produce revenues in excess of those found reasonable herein and should be denied.

2. Kentucky-American's proposed DSIC tariff rider and PPACC charge are unreasonable and should be denied.

3. Kentucky-American's proposed non-recurring charges are reasonable and should be approved.

4. The rates in the Appendix to this Order are fair, just, and reasonable and should be charged by Kentucky-American for service rendered on and after July 26, 2013.

5. Kentucky-American should, within 60 days of the date of this Order, refund to its customers with interest all amounts collected from July 26, 2013 through the date of this Order that are in excess of the rates that are set forth in the Appendix to this Order. Interest should be based upon the average of the Three-Month Commercial Paper Rate as reported in the Federal Reserve Bulletin and the Federal Reserve Statistical Release on the date of this Order.

IT IS THEREFORE ORDERED that:

1. Kentucky-American's proposed rates, except for those directly related to non-recurring services, are denied.

2. The rates set forth in the Appendix to this Order are approved for service rendered on and after July 26, 2013.

3. Within 60 days of the date of this Order, Kentucky-American shall refund to its customers with interest all amounts collected for service rendered from July 26, 2013, through the date of this Order that are in excess of the rates that are set forth in the Appendix to this Order.

4. Kentucky-American shall pay interest on the refunded amounts at the average of the Three-Month Commercial Paper Rate as reported in the Federal Reserve Bulletin and the Federal Reserve Statistical Release on the date of this Order. Refunds shall be based on each customer's usage while the proposed rates were in effect and shall be made as a one-time credit to the bills of current customers and by check to customers that have discontinued service since July 26, 2013.

5. Within 75 days of the date of this Order, Kentucky-American shall submit a written report to the Commission in which it describes its efforts to refund all monies collected in excess of the rates that are set forth in the Appendix to this Order.

6. Within 20 days of the date of this Order, Kentucky-American shall file using the Commission's Electronic Tariff Filing System its revised tariff sheets containing the rates approved herein and signed by an officer of the utility authorized to issue tariffs.

7. Any documents filed with the Commission pursuant to Ordering Paragraph 5 shall reference this case number and shall be retained in the utility's general correspondence file.

8. At least 90 days prior to the execution of any agreement to acquire a water system that is not subject to Commission jurisdiction, Kentucky-American shall advise the Commission in writing of the pending transaction, to include the name and location of the water system and a brief description of the transaction.

By the Commission

ENTERED
OCT 25 2013
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

OCT 2 5 2013

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2012-00520 DATED

The following rates and charges are prescribed for the customers in the area served by Kentucky-American Water Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of the Commission prior to the effective date of this Order.

Meter Charge Rates

Meter Size	
5/8-Inch	$ 12.45
3/4-Inch	18.68
1-Inch	31.13
1 1/2-Inch	62.25
2-Inch	96.60
3-Inch	186.75
4-Inch	311.25
6-Inch	622.50
8-Inch	996.00

Consumption Rates

Customer Category	Rate Per 100 Cubic Feet All Consumption	1,000 Gallons All Consumption
Residential	$3.9647	$5.30040
Commercial	3.6113	4.82800
Industrial	2.9132	3.89470
Municipal & Other Public Authority	3.1754	4.24520
Sales for Resale	3.1486	4.20930

Municipal or Private Fire Protection Service

Service Size	Rate Per Month	Rate Per Annum
2-Inch	$ 8.92	$ 107.04
4-Inch	35.90	430.80
6-Inch	80.74	968.88
8-Inch	143.54	1,722.48
10-Inch	224.34	2,692.08
12-Inch	323.50	3,882.00
14-Inch	439.89	5,278.68
16-Inch	574.42	6,893.04

Rates for Public or Private Fire Service

	Rate Per Month	Rate Per Annum
For each public fire hydrant contracted for or ordered by Urban County, County, State or Federal Governmental Agencies or Institutions	$ 41.60	$ 499.20
For each private fire hydrant contracted for by Industries or Private Institutions	79.77	957.24

Tapping (Connection) Fees

Meter Connection Size	
5/8-Inch	$1078.00
1-Inch	1,576.00
2-Inch	3,563.00
Service larger than 2-Inch	Actual Cost

Nonrecurring Charges

Activation Fee	$28.00
Reconnection Charge	56.00

Honorable David J. Barberie
Managing Attorney
Lexington-Fayette Urban County Government
Department Of Law
200 East Main Street
Lexington, KENTUCKY 40507

Monica Braun
STOLL KEENON OGDEN PLLC
300 West Vine Street
Suite 2100
Lexington, KENTUCKY 40507-1801

Janet M Graham
Commissioner of Law
Lexington-Fayette Urban County Government
Department Of Law
200 East Main Street
Lexington, KENTUCKY 40507

Jennifer B Hans
Assistant Attorney General's Office
1024 Capital Center Drive, Ste 200
Frankfort, KENTUCKY 40601-8204

Honorable Lindsey W Ingram, III
Attorney at Law
STOLL KEENON OGDEN PLLC
300 West Vine Street
Suite 2100
Lexington, KENTUCKY 40507-1801

Honorable Iris G Skidmore
415 W. Main Street
Suite 2
Frankfort, KENTUCKY 40601

Honorable David Edward Spenard
Assistant Attorney General
Office of the Attorney General Utility & Rate
1024 Capital Center Drive
Suite 200
Frankfort, KENTUCKY 40601-8204

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY-AMERICAN	)	
WATER COMPANY FOR AN ADJUSTMENT	)	CASE NO. 2010-00036
OF RATES SUPPORTED BY A FULLY	)	
FORECASTED TEST YEAR	)	

TABLE OF CONTENTS

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY-AMERICAN WATER COMPANY FOR AN ADJUSTMENT OF RATES SUPPORTED BY A FULLY FORECASTED TEST YEAR	))))	CASE NO. 2010-00036

O R D E R

Kentucky-American Water Company ("Kentucky-American") proposes to adjust its base rates for water service and increase its tap-on fees. The proposed rates, which were based upon a fully forecasted test period ending September 30, 2011, would produce additional revenues of $25,848,286, or 39.9 percent, over forecasted operating revenues from existing water rates of $64,753,488.[1] By this Order, the Commission establishes rates for water service that will produce an annual increase in revenues from water sales of $18,825,137 and approves the requested increase in tap-on fees.

BACKGROUND

Kentucky-American, a Kentucky corporation, owns and operates facilities that treat and distribute water, for compensation, to approximately 118,759 customers in the counties of Bourbon, Clark, Fayette, Gallatin, Grant, Harrison, Jessamine, Owen, Scott,

[1] As required by KRS 278.192(2)(b), Kentucky-American submitted its base period update on July 15, 2010 to report the actual results for the base period months that were originally forecasted. This update contains corrections of certain errors that result in a revised revenue increase of $25,302,362, or $545,924 below the originally proposed increase.

and Woodford.[2] It provides wholesale water service to Jessamine-South Elkhorn Water District, Harrison County Water Association, East Clark Water District, and the cities of Georgetown, Midway, Versailles, North Middletown, and Nicholasville.[3] It is a utility subject to Commission jurisdiction.[4] Kentucky-American last applied for a rate adjustment in 2008.[5]

PROCEDURE

On January 27, 2010, Kentucky-American notified the Commission in writing of its intent to apply for an adjustment of rates using a forecasted test period. On February 26, 2010, it submitted its application. The Commission established this docket[6] and permitted the following parties to intervene in this matter: the Attorney General of Kentucky ("AG"), Lexington-Fayette Urban County Government ("LFUCG"), and Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC").

On March 17, 2010, the Commission suspended the operation of the proposed rates for six months and established a procedural schedule for this proceeding. Following extensive discovery, the Commission held an evidentiary hearing in this

---

[2] *Annual Report of Kentucky-American Water Company to the Public Service Commission for the Calendar Year Ended December 31, 2009* at 5, 30.

[3] *Id.* at 33.

[4] KRS 278.010(3)(d).

[5] Case No. 2008-00427, Application of Kentucky-American Water Company for A General Adjustment of Rates Supported by A Fully Forecasted Test Year (Ky. PSC Jun. 1, 2009).

[6] On February 16, 2010, the Commission granted Kentucky-American's request for the use of electronic filing procedures in this proceeding and authorization for the service of all documents upon all parties by electronic means only.

matter on August 10-11, 2010 in Frankfort, Kentucky.[7] We also held a public hearing in Lexington, Kentucky on July 28, 2010 to receive public comment on the proposed rate adjustment. All parties submitted written briefs following the conclusion of the evidentiary hearing.

On September 28, 2010, Kentucky-American notified the Commission of its intent to place the proposed rates into effect for service rendered on and after September 29, 2010. In response, we directed Kentucky-American to maintain appropriate records of its billing to permit any necessary refunds.

ANALYSIS AND DETERMINATION

Test Period

Kentucky-American used as its forecasted test period the twelve months ending September 30, 2011. The base period was the twelve months ending May 31, 2010.

---

[7] The following persons testified at the evidentiary hearing: Patrick L. Baryenbruch, President, Baryenbruch & Company, LLC; Linda C. Bridwell, Manager-Water Supply, Kentucky-American; Keith Cartier, Vice-President of Operations, Kentucky-American; Paul R. Herbert, President, Valuation and Rate Division, Gannett Fleming, Inc.; Michael A. Miller, Assistant Treasurer, Kentucky-American; Sheila A. Miller, Manager-Rates and Service, Eastern Regional Service Company Office, American Water Service Company; Nick O. Rowe, President, Kentucky-American; John J. Spanos, Vice-President, Valuation and Rate Division, Gannett Fleming, Inc.; James L. Warren, Partner, Winston & Strawn LLP; Lance W. Williams, Director of Engineering, Kentucky-American; Ralph C. Smith, Senior Consultant, Larkin & Associates, PLLC; and Jack E. Burch, Executive Director, CAC. By agreement of the parties, the following persons submitted written testimony but did not make a personal appearance at the evidentiary hearing: James H. Vander Weide, Professor of Finance and Economics, Duke University; J. Randall Woolridge, Professor of Finance, Pennsylvania State University; Edward L. Spitznagel, Jr., Professor of Mathematics, Washington University; and Richard A. Baudino, Consultant, J. Kennedy and Associates, Inc.

Rate Base

Kentucky-American proposes a forecasted net investment rate base of $362,672,028.[8] The Commission accepts this forecasted rate base with the following exceptions:

Utility Plant in Service ("UPIS"). Kentucky-American uses capital construction budgets to determine its forecasted UPIS amount of $566,014,484.[9] A major component of Kentucky-American's forecasted UPIS is the $164 million cost of the Kentucky River Station II ("KRS II") project, which Kentucky-American placed into service on or about September 20, 2010. On April 25, 2008, the Commission granted Kentucky-American a Certificate of Public Convenience and Necessity to construct KRS II, approximately 30.6 miles of 42-inch transmission main to transport treated water to its Central Division distribution system, and a booster station in Franklin County.[10] Kentucky-American attributes $23,579,000, or approximately 91 percent, of its total requested rate increase of $25,848,000 to KRS II's construction and placement into service.[11]

---

[8] Application, Exhibit 37, Schedule B-1 at 2.

[9] *Id.*

[10] Case No. 2007-00134, The Application of Kentucky-American Water Company For a Certificate of Convenience and Necessity Authorizing the Construction of Kentucky River Station II, Associated Facilities and Transmission Main (Ky. PSC Apr. 25, 2008).

[11] Direct Testimony of Michael A. Miller at 4.

Kentucky-American separates its construction budgets into three categories: normal recurring construction, construction projects funded by others,[12] and major investment projects. In prior rate proceedings, the Commission has adjusted forecasted UPIS to reflect 10-year historical trend percentages of actual-to-budgeted construction spending.[13] We noted:

> Budgeting being an inexact science, it is imperative that the historical relationship between the budgets and actual results be reviewed to determine what projects Kentucky-American is likely to have in service or under construction in the forecasted period. A forecasted period does not preclude the examination of historic data and trends but, rather, compels their examination to test the historic to forecasted relationships. Nor will an adjustment based on the historical slippage factor have a devastating impact on Kentucky-American's earning potential. Such an adjustment will have a minimal impact on revenue requirements by eliminating a return on utility plant not in service during the forecasted period due to delayed investment.[14]

These “slippage factors” thus serve as an indicator of Kentucky-American’s accuracy in predicting the cost of its utility plant additions and the time period during which new plant will be placed into service.

---

[12] Contributions in Aid of Construction or Customer Advances, which are forms of cost-free capital, fund these projects.

[13] Case No. 92-452, Notice of Adjustment of Rates of Kentucky-American Water Company, at 9-11 (Ky. PSC Nov. 19, 1993); Case No. 95-554, The Application of Kentucky-American Water Company to Increase Its Rates, at 2-3 (Ky. PSC Sep. 11, 1996); Case No. 97-034, The Application of Kentucky-American Water Company to Increase Its Rates, at 3-7 (Ky. PSC Sep. 30, 1997); Case No. 2000-120, The Application of Kentucky-American Water Company to Increase Its Rates, at 2-4 (Ky. PSC Nov. 27, 2000); and Case No. 2004-00103, Adjustment of the Rates of Kentucky-American Water Company, at 3-4 (Ky. PSC Feb. 28, 2005).

[14] Case No. 92-452, Order of Nov. 19, 1993, at 9.

Based upon the evidence in the record, we find the slippage factors for normal recurring construction and major investment projects are 120.86 percent and 90.80 percent, respectively.[15] By applying these factors to its capital construction budgets, Kentucky-American recalculated its forecasted UPIS to be $569,054,823, or $3,040,399 greater than the original forecasted UPIS of $566,014,484.[16]

The AG objects to the application of any slippage factor in the current proceeding. He contends that slippage factors were originally intended to protect ratepayers from Kentucky-American's historical tendency to overestimate its construction spending and to serve as a safeguard to ensure that ratepayers did not bear the cost of paying a return for UPIS that would not be placed in service in the test period.[17] A "reverse-slippage" adjustment, the AG asserts, is unnecessary because "slippage was never intended to be a double-edged sword that cuts both ways; rather, the intent of the factor was a scalpel for the purpose of excising the risk associated with Kentucky-American's over-budgeting in setting rates."[18]

[15] Kentucky-American's Response to Commission Staff's First Information Request, Item 9.

[16] Kentucky-American's Response to Commission Staff's First Information Request, Item 36, Schedule B-1 at 2.

[17] AG's Brief at 18.

[18] *Id.*

We disagree with the proposition that slippage factors were intended solely to protect ratepayers. Their purpose is to produce a more accurate, reasonable, and reliable level of forecasted construction.[19] The application of slippage factors in this proceeding is consistent with that purpose and with the Commission's past practice in every rate case decision in which Kentucky-American proposed a rate adjustment based upon the use of a forecasted test period. Accordingly, we find that Kentucky-American's forecasted UPIS should be increased by $3,040,399 to reflect the application of slippage factors.

Accumulated Depreciation. In its application, Kentucky-American uses a 13-month average of its accumulated depreciation balances for the period from September 2010 through September 2011 to arrive at its forecasted accumulated depreciation of $110,085,251.[20] Adjusting Kentucky-American's forecasted accumulated depreciation to reflect the effect of construction slippages results in an increase of $62,956 for an adjusted balance of $110,148,207.[21]

In this application, Kentucky-American submits a recently completed depreciation study to support its forecasted depreciation. This study was based upon Kentucky-American's utility plant as of November 30, 2009.[22] In calculating the depreciation

---

[19] *See, e.g.*, Case No. 95-554, Order of Sep. 11, 1996, at 5 ("The 10 year slippage factor . . . produces a more reliable estimate of the construction projects Kentucky-American will have in service or under construction in the forecasted period.").

[20] Application, Exhibit 37, Schedule B-1 at 2.

[21] Kentucky-American's Response to Commission Staff's Second Information Request, Item 36, Schedule B-1 at 2.

[22] John J. Spanos, *Depreciation Study - Calculated Annual Depreciation Accruals Related to Utility Plant at November 30, 2009*, at I-1 (Gannett Fleming, Inc. Feb. 18, 2010) ("*Depreciation Study*").

accrual rates in this study, however, Kentucky-American failed to consider KRS II's projected cost.[23] Kentucky-American subsequently revised its study to reflect the cost of its forecasted UPIS as of December 31, 2010, which included KRS II costs of $163,891,660.[24] This revision reduces forecasted accumulated depreciation by $130,773.[25]

While generally accepting the findings of Kentucky-American's revised depreciation study, the AG asserts that the findings regarding Account 333, Services, are unsupported by credible evidence and appear suspect.[26] He notes that Kentucky-American proposes a negative net salvage value of 100 percent for this account, which is much higher than the negative net salvage value for other accounts.[27] He further notes that the study is missing information from calendar years 1995, 1996, 1997, and 1998 and that, although the study period involved 30 years, approximately 42 percent of the regular retirements for Account 333 occurred in 2007 and 2008.[28] Finally, he notes that the three-year moving averages for Account 333 for the last three years vary

---

[23] Direct Testimony of John J. Spanos at III-4 through III-11.

[24] Kentucky-American's Response to Commission Staff's Second Information Request, Item 43.

[25] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT).

[26] AG's Brief at 23.

[27] Public Direct Testimony of Ralph C. Smith at 69.

[28] *Depreciation Study* at III-106.

significantly from the study's findings.[29] Accordingly, the AG argues that Kentucky-American has failed to meet its burden of proof to demonstrate the reasonableness of the proposed depreciation rate for this account.

Notwithstanding the AG's argument, we find sufficient evidence to support the study's findings. We note that the study was based upon historical data gathered over a 30-year period and the study's methodology was systematically applied to all accounts. The AG has not suggested, nor do we find any evidence to indicate, that the utility concealed data or the report's preparers deliberately ignored data.[30] The AG has not suggested that the report's methodology was incorrectly applied or was contrary to industry-wide standards. Our review of the study indicates that its methodology is consistent with that of other depreciation studies that the Commission has accepted.[31]

---

[29] AG's Brief at 23. The three year moving averages for Account 333 are shown below:

3 Year Periods	Negative Percentages
2005 – 2007	41%
2006 – 2008	17%
2007 – 2009	19%

[30] The AG's acceptance of the study's findings for accounts other than Account 333 weakens his argument regarding Account 333. Data for a four-year period was not available and therefore not used in the study to calculate net salvage value for several accounts. If the lack of available data does not render the study's findings invalid or suspect for these other accounts, it logically follows the lack of data should not affect the study's findings for Account 333.

[31] *See, e.g.*, Case No. 9093, Application of Kentucky-American Water Company for Certification of Depreciation (Ky. PSC Mar. 21, 1985); Case No. 90-321, Notice of Adjustment of The Kentucky-American Water Company Effective on December 27, 1990 (Ky. PSC May 30, 1991); Case No. 95-554, Order of Sep. 11, 1996; Case No. 2007-00143, Adjustment of Rates of Kentucky-American Water Company (Ky. PSC Nov. 29, 2007).

Accordingly, the Commission finds that the AG's proposed adjustments to accumulated depreciation should be denied. We further find that accumulated depreciation should be adjusted to reflect the impact of slippage and the results of the revised depreciation study, which results in a net decrease to accumulated depreciation expense of $67,817.

Construction Work in Progress ("CWIP"). Kentucky-American forecasts CWIP includable in rate base as $9,463,931.[32] When adjusted for slippage, CWIP balance is $9,438,488.[33]

Arguing that CWIP should not be included in rate base unless a utility demonstrates compelling reasons for that treatment, such as a large project that cannot be financed without seriously jeopardizing the utility's financial health, and that Kentucky-American has failed to offer such reasons, the AG proposes to eliminate all CWIP balance from Kentucky-American's rate base.[34] AG witness Smith argues that CWIP does not represent facilities that are used or useful in the provision of utility service.[35] Including this plant in rate base, he argues, requires current ratepayers to pay a return on plant that is not providing them with utility service. Moreover, he further argues, it creates a mismatch in the rate-making process by permitting a return on

---

[32] Application, Exhibit 37, Schedule B-1, at 2.

[33] Kentucky-American's Response to Commission Staff's Second Information Requests, Item 36, at 4.

[34] Public Direct Testimony of Ralph C. Smith at 13; AG's Brief at 25-26.

[35] Public Direct Testimony of Ralph C. Smith at 14.

investment in facilities that will not be in service until after the close of the test period and that will serve new customers without consideration of the revenues that will be generated from those new customers or the possible reduction in present expense levels due to these facilities.[36]

We have previously addressed and rejected these arguments.[37] In the current proceeding, the AG has not produced, nor have we discovered, any legal authority to require us to alter our earlier holding and to find that the use of a forecasted test period prohibits the inclusion of CWIP in a utility's rate base.

We question why the inclusion of CWIP is acceptable when a historic test period is employed, but is unacceptable when a forward-looking test period is used. KRS 278.192 makes no such distinction. "[T]he purpose of a forecasted test year is to reduce the regulatory lag experienced in historical test period rate cases by forecasting and matching revenue requirements and rates with the actual 12-month period for which the rates will first be placed into effect."[38] Aside from the test period used, all other rate-making principles and methodologies should remain unchanged. The AG has provided no argument or legal authority to support a contrary result.

We also find no support for the proposition that inclusion of CWIP in rate base is limited to instances where the utility's financial health is at issue. Historically, we have permitted rate base recovery of CWIP, in large measure, to prevent rate shock. For example, in Case No. 10069, we stated:

---

[36] *Id.* at 15.

[37] Case No. 2004-00103, Order of Feb. 28, 2005, at 11-12.

[38] *Id.* at 12.

> Kentucky-American is currently operating in a construction mode, which will require large additions to capital. In these circumstances rate base recovery of the actual end-of period CWIP results in a series of smaller rate increases rather than awaiting completion of the projects to impose one large rate increase. This is one of the reasons the Commission has historically allowed Kentucky-American to earn a return on its CWIP investment.[39]

Clearly, CWIP is not tied merely to the financial health of the regulated utility.

Finally, we find no merit in the AG's contention that the Commission's treatment of CWIP places an unfair and unnecessary burden on ratepayers. Generally, regulated utilities recognize the carrying costs of construction in rates through one of two methods: inclusion of CWIP in rate base or accrual of Allowance for Funds Used During Construction ("AFUDC"). This Commission has, in previous Kentucky-American rate proceedings, applied a hybrid approach that combines these two methods. This approach allows Kentucky-American to include all CWIP in rate base while accruing AFUDC on projects taking longer than 30 days to complete. Under this approach, AFUDC revenue is reported "above the line." This approach eliminates the effects of including AFUDC bearing CWIP in rate base. It further allows Kentucky-American to accrue AFUDC as part of an asset's cost where appropriate and to earn a return on CWIP where AFUDC is not accrued.

Based upon the above, the Commission has decreased Kentucky-American's forecasted CWIP of $9,463,931 by $25,443 to recognize the effects of construction slippages.

---

[39] Case No. 10069, Notice of Adjustment of the Rates of Kentucky-American Water Company, at 4-5 (Ky. PSC July 31, 1996).

Working Capital. Kentucky-American used a lead/lag study that employs the methodology approved in prior Kentucky-American rate proceedings to calculate cash working capital allowance. No party proposed adjustments to this methodology.[40]

In its application, Kentucky-American includes a cash working capital allowance of $2,634,000 in its forecasted rate base.[41] It subsequently reduced this amount by $493,000 to $2,141,000 to reflect the effect on cash working capital of its corrections to the forecasted operating expenses and to Annual Incentive Plan ("AIP") lag days.[42]

AG witness Smith recommends that Kentucky-American's working capital allowance be reduced by $980,000, to $1,654,000, to reflect the effects on working capital allowance of his other recommended adjustments.[43] He further recommends that the lead/lag study be updated to reflect the Commission's findings in this proceeding.[44]

After applying all reasonable and necessary adjustments to Kentucky-American's forecasted working capital calculation and correcting for the AIP lag days, the

---

[40] AG witness Smith took exception to Kentucky-American's inclusion, with a zero-day payment lag, in the lead/lag study of non-cash items such as depreciation, amortization, deferred income taxes, and a return on equity. Recognizing that the Commission had accepted this practice in previous rate proceedings, he did not propose exclusion of these components. Public Direct Testimony of Ralph C. Smith at 17-18.

[41] Application, Exhibit 37, Schedule B, at 2.

[42] Base Period Update Filing, Exhibit 37, Schedule B, at 3 (filed July 15, 2010); Kentucky-American's Response to AG's Second Request for Information, Item 118.

[43] Public Direct Testimony of Ralph C. Smith at 19 and Exhibit RCS-1, Schedule B-3.

[44] *Id.* at 19.

Commission finds the appropriate working capital allowance to be $1,729,000, a decrease of $905,000 to Kentucky-American's forecasted level.

Contributions in Aid of Construction ("CIAC"). In its application, Kentucky-American includes CIAC of $48,865,890[45] as a reduction to rate base. We find that this amount should be increased by $916,100, to $49,781,990, to reflect the effects of construction slippage.[46]

Customer Advances. In its application, Kentucky-American identifies customer advances as $19,089,182.[47] The Commission finds that customer advances should be increased by $792,057, to $19,881,239, to reflect the effects of construction slippage.[48]

Deferred Maintenance. Kentucky-American incurs maintenance expenses (e.g., tank and hydrator painting and repairs, station cleaning) for which the Commission has historically allowed deferred accounting treatment. With such expenses, Kentucky-American is permitted annual recovery of allowed amortization expense. The unamortized balance of these expenses is generally included in rate base. All amounts allowed were based on actual costs from historical periods. In its application, Kentucky-American proposes the inclusion of $2,708,236 of deferred maintenance in its rate base.[49]

---

[45] Application, Exhibit 37, Schedule B, at 2.

[46] Kentucky-American's Response to Commission Staff's Second Information Request, Item 36, Schedule B-1, at 2.

[47] Application, Exhibit 37, Schedule B, at 2.

[48] Kentucky-American's Response to Commission Staff's Second Information Request, Item 36, Schedule B-1, at 2.

[49] Application, Exhibit 37, Schedule B, at 2.

AG witness Smith proposes that Kentucky-American's deferred maintenance be reduced by 1.68 percent, or $45,500, to remove the internal labor costs.[50] In support of his recommendation, he notes that the Commission had held in Case No. 2000-120 that deferred labor expenses should not be included in a proposed acquisition adjustment[51] and that, in Kentucky-American's last rate proceeding, Kentucky-American had acknowledged that 1.68 percent of its 13-month average deferred maintenance cost balance represented deferred labor costs.

Opposing the proposed adjustment, Kentucky-American argues that AG witness Smith failed to make an independent calculation to determine if the 1.68 percent labor adjustment accurately reflects the portion of labor expense presently in deferred maintenance, but instead relied upon testimony and responses to discovery requests in a prior rate case.[52] In light of this failure and the lack of any other supporting evidence, Kentucky-American argues that Mr. Smith's testimony should be afforded little weight.

Kentucky-American further argues that the presence of a small labor component within deferred maintenance does not result in double recovery of labor expenses. Kentucky-American witness Michael Miller noted that Kentucky-American's forecasted test-year operation and maintenance labor is determined by applying an appropriate capitalization rate to total labor and labor-related benefit costs. Since the engineering

---

[50] Public Direct Testimony of Ralph C. Smith at 19-20.

[51] Case No. 2000-00120, Order of May 9, 2001, at 8 (stating that "[t]o defer payroll expense between rate cases and then amortize those costs, in addition to the normal recurring payroll expense, would artificially inflate forecasted test year operations"); Public Direct Testimony of Ralph C. Smith at 20.

[52] Kentucky-American's Brief at 22.

costs charged to deferred maintenance, such as tank inspections, are embedded in the utility's capitalization rate, the utility is not recovering those costs as an expense in the forecasted test period, but is only recovering those costs through the amortization of the deferred maintenance over the life of the maintenance job.[53]

We find insufficient evidence to support the proposed adjustment. There is no evidence in the record to support the current level of labor costs within the deferred maintenance. Reliance upon a record developed almost two years ago is not sufficient. Moreover, we are not convinced that the presence of some labor expense in deferred maintenance will result in double recovery on the utility's part. Accordingly, we find that deferred maintenance of $2,708,236 should be allowed in rate base.

Deferred Taxes. In its application, Kentucky-American reduced rate base by accumulated deferred income tax of $40,026,731.[54] Included in deferred income taxes are items approved in prior rate cases: UPIS, deferred maintenance, and deferred debits.[55] Statement of Financial Accounting Standards 109 – Accounting for Income Taxes has been incorporated in the rate base deduction for income taxes and forecasted income tax expense.[56]

Accumulated deferred income taxes have been adjusted as shown in Table I to account for all adjustments made related to items affecting deferred taxes.

---

[53] Rebuttal Testimony of Michael A. Miller at 18-19.

[54] Application, Exhibit 37, Schedule B-6, at 2.

[55] *Id.*

[56] Direct Testimony of Sheila A. Miller at 14.

Table I: Accumulated Deferred Income Taxes		
13-Month Average Accumulated Def. Inc. Tax - Application	$	40,026,731
Slippage		(1,474)
Deferred Compensation - Summary of Revisions		24
Adj. Dep. Rates for KRS II - Summary of Adjustments		73,262
Adj. Tax Exempt Finance - Summary of Revisions	+	(188)
Accumulated deferred Income Tax Adj.	$	40,098,355

Major Tax Accounting Change. On December 31, 2008, Kentucky-American, as a member of a consolidated group of American Water Works Company ("AWWC") subsidiaries, requested authorization from the Internal Revenue Service ("IRS") to change its accounting method for recording repairs and maintenance. Instead of capitalizing repairs and maintenance costs, the members of the consolidated group sought to deduct these costs in the current tax year. In February 2010, the IRS approved the request and Kentucky-American recognized a tax deduction for costs that previously were capitalized for tax purposes.[57] Kentucky-American and the other members of the consolidated group take the position, however, that the IRS ruling fails to address a critical component of the deduction calculation and that this failure creates uncertainty regarding the lawfulness of the deduction. In light of the uncertainty, Kentucky-American asserts, Financial Accounting Standards Board Interpretation No. 48 ("FIN 48") requires the creation of a reserve for a portion of the capitalized repairs deduction to permit payment of any potential tax liability.

[57] Kentucky-American's Response to the AG's Second Request for Information, Item 85 at 20-21.

FIN 48 requires entities to identify their uncertain tax positions, evaluate each position on its merits, and determine if the IRS is likely to sustain the deduction.[58] Kentucky-American contends that it is complying with FIN 48 by establishing a liability account to record the amount of deferred taxes that the IRS would likely deny.

There are two possible outcomes for the FIN 48 account. First, the uncertainty is removed by a formal IRS audit or the expiration of the statute of limitations or a change in existing tax laws. The FIN 48 entries are then reversed and treated as cost-free capital. Alternatively, the IRS disallows the deduction and eliminates the benefit to Kentucky-American. In that event, the interest rate that the IRS will apply is 4 percent, a rate significantly below Kentucky-American's requested weighted cost of capital of 8.58 percent. Kentucky-American has agreed not to seek recovery from its ratepayers if the IRS ultimately requires any interest or penalties on the FIN 48 account provided the Commission, pending a final IRS determination, makes no adjustment for rate-making purposes to Kentucky-American's deferred taxes because of the FIN 48 account.[59]

The AG asserts that the change in accounting method has been made and that Kentucky-American is realizing a benefit–a zero-cost capital–without passing this

---

[58] Financial Accounting Standards Board Interpretation No. 48, Accounting for Uncertainty in Income Taxes (June 2006), available at http://www.fasb.org/cs/BlobServer?blobcol=urldata&blobtable=MungoBlobs&blobkey=id&blobwhere=1175820931560&blobheader=application%2Fpdf. On July 1, 2009, the Financial Accounting Standards Board ("FASB") finalized its Accounting Standards Codification ("ASC"), creating a new system of reference for all past FASB pronouncements. Under the new codification system, FIN 48 will now be referred to as ASC Topic 740, but many practitioners continue to use the "FIN 48" nomenclature.

[59] Kentucky-American's Brief at 20.

benefit to the ratepayers.[60] He proposes two options: (1) the Commission increases Kentucky-American's accumulated deferred income taxes by the FIN 48 liability and recognizes the benefit with an interest amount for the FIN 48 reserve that is recorded above the line; or (2) Kentucky-American records the interest below the line in tandem with the creation of a regulatory asset. If the first option is employed and IRS does not disallow the deduction, Kentucky-American would make a refund to its ratepayers. If the second option is selected and the IRS disallows the deduction and assesses interest against Kentucky-American, the utility may request recovery of the interest in a future rate case proceeding.[61]

Few regulatory commissions have addressed this issue in contested proceedings. Those commissions have been reluctant to apply the rate-making treatment that the AG proposes. Finding that utilities should be encouraged to take uncertain positions with the IRS since "ratepayers and shareholders benefit when . . . [a utility] takes an uncertain tax position with the IRS, because saving money on taxes benefits the company's bottom line and reduces the amount of expense the ratepayers must pay," the Missouri Public Service Commission rejected a proposed adjustment to recognize FIN 48 liabilities as deferred income taxes.[62] The Washington Utilities and

---

[60] AG's Brief at 5-6.

[61] *Id.*

[62] In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase Its Annual Revenues for Electric Service, Case No. ER-2008-0318, slip. op. at 55 (Mo. PSC Jan. 6, 2009).

Transportation Commission rejected a similar proposal and noted the risks of recognizing IRS accounting changes before all uncertainty is eliminated.[63]

We agree with the holding of those decisions and decline to adopt the AG's proposed adjustment to Kentucky-American's accumulated deferred income taxes. Kentucky-American determined that some uncertainty exists regarding the legality of the deduction related to the change in accounting methods. No party challenges the reasonableness of this determination or the appropriateness of establishing a reserve in the event of an adverse IRS ruling. Kentucky-American's action, moreover, is consistent with FIN 48. If the IRS ultimately allows the deduction or the statute of limitations expires without a challenge to the deduction, ratepayers and shareholders will benefit from the tax deferral. If the IRS disallows Kentucky-American's deduction, Kentucky-American has stated that it will not seek recovery for interest and penalties imposed by the IRS and the ratepayers will not be negatively affected.

Deferred Debits. In its application, Kentucky-American includes $1,700,474 in rate base to reflect the unamortized 13-month average of several deferred debits. Approximately $2,342 of this amount represents the unamortized acquisition adjustment related to the purchase of Boonesboro Water Association's assets. Kentucky-American has acknowledged erroneously including this unamortized acquisition adjustment twice in rate base.[64] The AG proposes to reduce deferred debits by $2,342 to correct this

[63] Washington Utilities and Transportation Commission v. Puget Sound Energy, Inc., Dockets UE-090704 and UG-090705, slip op. at 70 (Wash. UTC April 2, 2010).

[64] Kentucky-American's Response to Commission Staff's Second Information Request, Item 41.

error. Accordingly, the Commission finds that deferred debits should be reduced by $2,342.

Other Rate Base Elements. In its application, Kentucky-American included a reduction to rate base for "other rate base elements" in the amount of $2,349,854. Other rate base elements include contract retentions, unclaimed extension deposit refunds, accrued pensions, retirement work in progress, and deferred compensation. Kentucky-American subsequently discovered that the deferred compensation is no longer being deferred and that "other rate base elements" should be decreased by $188,379.[65] The correct amount of "other rate base elements" is $2,161,475. The Commission finds that other rate base elements should be reduced by $188,379, which results in an increase to rate base.

Based on the adjustments discussed above, the Commission has determined the company's net investment rate base to be as shown in Table II.

[65] Rebuttal Testimony of Sheila A. Miller at 2; Kentucky-American's Response to AG's First Information Request, Item 25.

Table II: Rate Base Comparison

Rate Base Component	Kentucky-American's Proposed 13-Month Average	Commission Adjustment	Commission Approved
UPIS	$ 566,014,484	$ 3,040,339	$ 569,054,823
Utility Plant Acquisition Adj.	2,342	0	2,342
Accumulated Depreciation	(110,085,251)	67,817	(110,017,434)
Net Utility Plant in Service	$ 455,931,575	$ 3,108,156	$ 459,039,731
CWIP	9,463,931	(25,443)	9,438,488
Working Capital Allowance	2,634,000	(905,000)	1,729,000
Other Working Capital	642,421	0	642,421
CIAC	(48,865,890)	(916,100)	(49,781,990)
Customer Advances	(19,089,182)	(792,057)	(19,881,239)
Deferred Income Taxes	(40,026,731)	(71,624)	(40,098,355)
Deferred Investment Tax Cr.	(76,952)	0	(76,952)
Deferred Maintenance	2,708,236	0	2,708,236
Deferred Debits	1,700,474	(2,342)	1,698,132
Other Rate Base Elements	(2,349,854)	188,379	(2,161,475)
Net Original Cost Rate Base	$ 362,672,028	$ 583,969	$ 363,255,997

Income Statement

For the base period, Kentucky-American reports operating revenues and expenses of $67,042,231 and $53,225,929, respectively.[66] Kentucky-American proposes several adjustments to revenues and expenses to reflect the anticipated operating conditions during the forecasted period, resulting in forecasted operating revenues and expenses of $68,523,625 and $53,050,358, respectively.[67] The Commission accepts Kentucky-American's forecasted operating revenues and expenses with the following exceptions:

[66] Application, Exhibit 37, Schedule C-2.

[67] *Id.*

AFUDC. In its application, Kentucky-American proposes to increase forecasted operating revenues by $646,180[68] to include an allowance for AFUDC. In calculating this forecast, Kentucky-American uses the weighted cost of capital requested in this proceeding of 8.58 percent.[69] To reflect the effect of slippage on CWIP, Kentucky-American adjusts AFUDC by $35,177 for an adjusted level of $629,114.[70] Kentucky-American also reduces AFUDC by $957 to reflect its correction for deferred compensation and the additional tax-exempt financing it received.

To correspond with his adjustment to eliminate CWIP from rate base, the AG proposes to reduce Kentucky-American's operating revenues by $646,180 to move AFUDC to "below-the-line" non-operating revenues. The Uniform System of Accounts for Class A and B Water Companies requires AFUDC to be recorded in non-operating revenues or "below-the-line." For rate-making purposes, the Commission allows Kentucky-American to earn a return on forecasted CWIP in rate base while offsetting the return by moving AFUDC to "above-the-line" operating revenues. This approach eliminates the effects of including the AFUDC bearing CWIP in rate base while allowing Kentucky-American to earn a return on CWIP where AFUDC is not accrued.

To be consistent with our rejection of the AG's proposal to remove CWIP from rate base, the Commission finds that operating revenues should be adjusted to reflect the inclusion of AFUDC. Using CWIP available for AFUDC and the overall rate of return of 7.74 percent, the Commission calculates a forecasted level of AFUDC of $611,003.

---

[68] *Id.*, Schedule D-1, at 1.

[69] *Id.*, Schedule J-1.1/J-2.1, at 1.

[70] Kentucky-American's Response to Commission Staff's Second Information Request, Item 36, at 1.

This action, when combined with Kentucky-American's revisions, results in a decrease to Kentucky-American's forecasted operating revenues of $44,094.[71]

Labor Expense. In its application, Kentucky-American includes forecasted operations labor expense of $8,039,622. In forecasting its labor expense, Kentucky-American uses 153 full-time employees, each scheduled to work 2,088 regular hours. It also includes overtime for some employees based upon historical levels. Labor costs for the sewer operations were removed from the forecasted labor expenses.[72]

- Employee Vacancies. Kentucky-American contends that, with the use of a forecasted test period, two methods are available to address employee vacancies. First, it can project the salaries and wages based upon the assumption that all employee positions are filled. This method recognizes that, while vacancies may occur throughout the year, the job requirements associated with those vacancies continue to exist and must be met. Second, it can estimate the average number of vacancies expected to occur throughout the forecasted period and quantify the level of temporary and overtime labor that will be necessary to perform the tasks associated with the vacant position. Kentucky-American employed the first option in developing its forecasted labor expense.[73]

Proposing an adjustment to eliminate the average cost of three positions,[74] the AG takes exception to Kentucky-American's approach. He argues that some vacancies

[71] $43,137 (Slippage) + $304 (Deferred Compensation) + $653 (Tax Exempt Financing) = $44,094.

[72] Direct Testimony of Sheila A. Miller at 6.

[73] Rebuttal Testimony of Sheila A. Miller at 6.

[74] Public Direct Testimony of Ralph C. Smith at 72-73.

should be expected at Kentucky-American throughout the year due to terminations, retirements, and changing work requirements, and affords little weight to Kentucky-American's claim that the utility has coordinated its assignment of a full-employee count with its projections of overtime and temporary employees. "[I]t does not follow," he argues, "that the items are mirror images of each other (i.e., that the dollar amounts are the same under either scenario)."[75] AG witness Smith proposed the adjustment based upon his review of Kentucky-American's historic employee vacancy rate.

The AG's proposed adjustment is similar to those that we have rejected in prior Kentucky-American rate proceedings because of its failure to "consider the vacancies' effect on Kentucky-American's overtime and temporary/contract forecasts."[76] We continue to adhere to this position. If vacant employee positions exist, work will either be shifted to other employees and thus result in an increase in overtime costs or Kentucky-American will hire additional temporary/contract labor. Kentucky-American has shown that its forecasts for overtime and temporary/contract labor have been reduced to reflect a full workforce. The vacant employee positions to which the AG refers will result in decreased direct labor costs, but that decrease will be offset by increases in overtime or temporary labor costs. Therefore, the overall impact of these vacancies on Kentucky-American's operating expenses and ultimately its revenue requirement is unknown. Accordingly, we deny the AG's proposed adjustment.

---

[75] AG's Brief at 27-28.

[76] Case No. 2004-00103, Order of Feb. 28, 2005, at 44. *See also* Case No. 95-554, Order of Sep. 11, 1996, at 32 ("The AG's proposed adjustment is flawed because it did not take into consideration the total 1995 labor costs.").

- Projected Pay Increases. AG witness Smith proposes a 0.4 percent reduction in the forecasted payroll expense to compensate for the utility's alleged historic over-projection of such expenses. He contends that Kentucky-American over-projected pay increases by 0.5 percent for union employees and 0.3 percent for non-bargaining unit employees for the years 2007-2009.[77] The AG argues that the variances are significant enough to warrant some adjustment in the rate-making process, at least in regard to those employees who are not under a collective bargaining agreement.[78] Although the AG states that Kentucky-American has shown in its rebuttal evidence that the contractual increases are known and certain and that they are reliable in setting rates, he nonetheless contends that the historical evidence of over-projection warrants an adjustment to the remaining non-contractual increases.

Opposing the proposed adjustment, Kentucky-American notes that pay increases for the union employees are pursuant to an existing union contract and are therefore certain and fixed. Its current contract with union employees requires a 3 percent increase for such employees. It further notes that its forecasted payroll expense for non-union employees is based upon quantifiable salary and wage increases.[79]

Having reviewed the record, we find insufficient evidence to support the forecasted payroll expense. The existing contract between Kentucky-American and Local Union 320 of the National Conference of Firemen and Oilers ended on

---

[77] Public Direct Testimony of Ralph C. Smith at 74.

[78] AG's Brief at 28.

[79] Rebuttal Testimony Sheila A. Miller at 7.

October 31, 2010.[80] The record contains no evidence that a new contract has been negotiated or the current contract extended. As Kentucky-American has asserted that projected pay increases for its salaried employees are intended to equal the projected increases to its union employees, its failure to adequately demonstrate that its contract with its union employees requires such increases casts doubt on the reasonableness of its projected increases for salaried employees. Given the lack of evidence on the certainty and reliability of the projected wage and salary increases, we find that the proposed increases should be removed from the forecasted test-period expenses. Elimination of the forecasted wage increases for all Kentucky-American employees, excluding three employees transferred to American Water Works Service Company ("Service Company"), results in a decrease to forecasted labor expense of $186,828.[81]

- Capitalization Rate. In its application, Kentucky-American uses a capitalization rate of 17.34 percent to apportion the forecasted payroll between the operation and maintenance expense account and the capital accounts. It subsequently revised this rate to 17.8 percent to reflect the transfer of three employee positions from Kentucky-American to the Service Company.[82]

Witnesses for the AG and LFUCG dispute the proposed capitalization rate. AG witness Smith proposes a capitalization rate of 19.472 percent. He contends that

---

[80] Kentucky-American's Response to Commission Staff's First Request for Information, Item 20, at 2-26.

[81] Assuming arguendo that Kentucky-American had provided sufficient evidence to demonstrate the certainty of the proposed increases, the Commission has concerns regarding the reasonableness of the magnitude of the proposed increase in labor expense in light of present economic conditions, both locally and nationally.

[82] Rebuttal Testimony of Sheila A. Miller at 9.

Kentucky-American's capitalization rate has fluctuated significantly in the last five years and that Kentucky-American's budgeted capitalization rates have been below actual rates for the three-year, four-year, and five-year averages through 2009.[83] In lieu of the forecasted rate of 17.8 percent, Mr. Smith proposes the use of a capitalization rate based upon a five-year average. LFUCG witness Baudino expresses similar concerns and recommends the same adjustment.[84]

Responding to these arguments, Kentucky-American notes that the capitalization rate depends on several factors, including the construction budget, the number of water main breaks that are expensed in capital accounts, and the number of water main extensions that developers fund.[85] While conceding that the capitalization rate for the forecasted period is lower than the rate presented in its last rate case proceeding, it asserts that this change is attributable to the addition of seven new employees who will be responsible for KRS II's operation.[86] If these seven new employees devote their total time to operation and maintenance functions, Kentucky-American asserts, the percentage of operation and maintenance expense must increase and the capitalization rate correspondingly decrease.

The Commission finds that Kentucky-American's explanation is reasonable and consistent with the evidence of record and the expected operation of KRS II. While the

---

[83] Public Direct Testimony of Ralph C. Smithat 69.

[84] Direct Testimony of Richard A. Baudino at 48-50.

[85] Kentucky-American Brief at 26-28.

[86] Kentucky-American's Response to Commission Staff's Second Request for Information, Item 13(b).

use of averages may be appropriate to identify an area for further review, it is not sufficient to justify the proposed adjustment. Given the wide array of factors that affect the capitalization rate and the failure of the AG and LFUCG to provide any evidence on those factors, we find insufficient evidence to support the proposed increase in the forecasted capitalization rate and deny the proposed adjustment.

- Employee Transfer. Since the filing of Kentucky-American's application, three positions on Kentucky-American's payroll have been transferred to the Service Company's payroll.[87] These transfers reduce Kentucky-American's forecasted payroll expense by $240,001.[88] The Commission finds that an adjustment to reflect the employee transfer should be made to Kentucky-American's forecasted labor expense and, therefore, accepts Kentucky-American's proposed reduction of $240,001 to reflect the transfer of the three Kentucky-American employees to the Service Company.

- Incentive Compensation Plan ("ICP"). In its forecasted labor expense, Kentucky-American includes an expense of $349,529 related to incentive compensation.[89] The AG proposes the removal of this expense from forecasted labor expense. Noting that funding for any AIP award is based upon the utility meeting threshold targets tied to the utility's Diluted Earnings Per Share, the AG contends that the AIP's sole purpose is enhancing shareholder value and return. To the extent that the program primarily benefits shareholders, the AG argues, shareholders should bear

---

[87] Rebuttal Testimony of Sheila A. Miller at 4-5.

[88] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT).

[89] Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), WP 3-2, at 2.

the burden of funding the program.[90] The AG further argues that Kentucky-American has failed to offer any quantitative support for its claims that AIP benefits ratepayers and, therefore, has failed to meet its burden to demonstrate the reasonableness of the expense.

Kentucky-American takes strong exception to the AG's contentions. It argues that the AIP is part of Kentucky-American's overall compensation package for its employees. AIP is intended, it asserts, to benefit customers through better service and more efficient costs. The program's incentives are directly tied to an employee's performance above the standard duties in his job description. The AIP and other incentive programs, Kentucky-American further argues, are necessary because the utility must compete for qualified employees in the markets in which it operates. The lack of such programs would limit its ability to attract and retain strongly performing employees when other surrounding businesses offer more competitive compensation packages.[91]

Kentucky-American argues that the AG has incorrectly concluded from the use of financial targets in the AIP program that the program's sole purpose is increasing stockholder value. While acknowledging that incentives are awarded only if the company meets certain financial targets, Kentucky-American asserts that targets are present only to ensure that the utility is fiscally able to award the incentive

---

[90] AG's Brief at 12-13.

[91] Kentucky-American's Response to Commission Staff's Second Information Request, Item 4.

compensation.[92] To do otherwise, it argues, would be financially irresponsible. Furthermore, Kentucky-American argues, several non-financial factors, such as safety, environmental goals, customer satisfaction, business transformation, and diversity, also determine the size of the incentive compensation pool.[93] Once financial targets are met and the utility is thus deemed to be financially fit to award incentives, the incentives are awarded solely on an employee satisfying or exceeding individual performance goals pertaining to specific areas of responsibility for the employee.[94]

In prior proceedings, the Commission has refused to permit Kentucky-American's recovery of AIP costs through rates and has placed the utility on notice that "[t]he mere existence of such [incentive compensation] plans is insufficient to demonstrate that they benefit ratepayers and that their costs should be recovered through rates" and that the utility must demonstrate why shareholders should not bear the costs associated with such plans.[95]

To meet this burden, Kentucky-American produced a study that allegedly "identified and quantified the benefits that inure to ratepayers pursuant to the incentive compensation plan."[96] This study compares the cumulative increase in Kentucky-

---

[92] Rebuttal Testimony of Michael A. Miller at 29-30.

[93] *Id.*

[94] *Id.* at 27.

[95] Case No. 2004-00103, Order of Feb. 28, 2005 at 49; *see also* Case No. 2000-120, Order of Nov. 27, 2000, at 44 (placing Kentucky-American "on notice that, in future rate proceedings, it must demonstrate fully why shareholders should not bear a portion of these costs").

[96] Kentucky-American's Brief at 52; Rebuttal Testimony of Michael A. Miller, Exhibit MAM-6.

American's operation and maintenance expense per customer to the cumulative increase in the Consumer Price Index ("CPI") for the five-year period from 2004 through 2009. Kentucky-American claims that its study demonstrates that, since 2005, Kentucky-American's increases in operation and maintenance costs per customer have consistently been below those of the CPI and that the utility has "successfully been able to resist cost increases more successfully than others."[97]

The study's results are inconclusive at best. For three years of the five-year period that the study considered, Kentucky-American's operations and maintenance expense on a per-customer basis increased at an annual rate that exceeded the annual increase in CPI. Kentucky-American's cumulative increase in operation and maintenance expense for the five-year period exceeded the cumulative increase in the CPI. Furthermore, the study fails to demonstrate any correlation between the rate of increase in its operation and maintenance expense per customer and its use of incentive compensation plans. It provides no comparison between its performance during the study period and that of firms that offer no incentive compensation plan to their employees. It makes no effort to eliminate or isolate the effects of other factors, such as AWWC's reorganization efforts, on Kentucky-American's operation and maintenance costs per customer.

We remain unconvinced that Kentucky-American's ratepayers receive any benefit from the AIP program to support the recovery of AIP's costs through rates. While some consideration is given to non-financial criteria, the AIP appears weighted to financial goals that primarily benefit shareholders. If these goals are not met, the

[97] Kentucky-American's Brief at 52.

program is unfunded and no Kentucky-American employee receives an incentive award regardless of how well he or she meets the customer satisfaction or service quality goals. Accordingly, we find that forecasted labor expense should be decreased by an additional $349,529 to eliminate the ICP.

- Stock-Based Compensation. Kentucky-American includes stock-based compensation of $27,228 in forecasted labor expense. This compensation involves stock-based awards and grants of stock options to employees based upon the attainment of performance goals or other conditions. The purpose of Kentucky-American's stock-based compensation plan is to "encourage the participants to contribute materially to the growth of the Company, thereby benefiting the Company's stockholders, and will align the economic interest of the participant with those stockholders."[98]

Arguing that this program primarily benefits shareholders, the AG proposes the removal of this program's costs from forecasted labor expense.[99] Opposing the proposed adjustment, Kentucky-American contends that the program benefits ratepayers by increasing management personnel's investment in the company. If management views itself as a stakeholder in the company, Kentucky-American argues, it will perform to maximize the company's success by increasing efficiency, productivity, and cost containment actions that also benefit ratepayers.

---

[98] Kentucky-American's Response to AG's First Request for Information, Item 15, at 25.

[99] Public Direct Testimony of Ralph C. Smith at 46-47.

The Commission finds that, based upon the stated purpose of the program, the program primarily benefits shareholders. In the absence of clear and definitive quantitative evidence demonstrating a benefit to the utility's ratepayers, the ratepayers should not be required to bear the program's costs. Accordingly, we find that forecasted labor expense should be decreased by $27,288 to eliminate the stock-based compensation plan.

Fuel and Power. In its forecasted operations, Kentucky-American includes fuel and power expense of $4,375,584. It used an unaccounted-for water loss percentage of 14 percent to forecast pumpage.[100] Kentucky-American's present unaccounted-for water loss is 11.8 percent.[101] Using this percentage, Kentucky-American calculated a revised fuel and power expense of $4,297,587, which is $77,997 below its original forecast.[102] Accordingly, the Commission finds that Kentucky-American's forecasted fuel and power expense should be decreased by $77,997.

Chemicals. In its forecasted operations, Kentucky-American included chemical expense of $1,772,730. As with its forecasted fuel and power expense, Kentucky-American used an unaccounted-for water loss of 14 percent to forecast chemical

---

[100] Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), WP 3-2, at 18.

[101] VR: 8/10/10; 15:45:45 -15:46:05. The present level represents a significant achievement for Kentucky-American. For the three-year period from January 1, 2006 through December 31, 2008, Kentucky-American's average line loss was 13.51 percent. For the year ending December 31, 2006, Kentucky-American experienced a line loss of approximately 14.94 percent. The Commission applauds Kentucky-American's efforts in this area.

[102] Kentucky-American's Response to Hearing Data Requests, Item 7, at 1.

expense.[103] Using the current water-loss percentage of 11.8 percent, Kentucky-American calculated a revised chemical expense of $1,729,077, which is $43,653 below its original estimate.[104] Accordingly, the Commission finds that Kentucky-American's forecasted chemical expense should be decreased by $43,653.

Waste Disposal. In its forecasted operations, Kentucky-American includes waste disposal expense of $340,226. This expense includes the amortization of the forecasted cost of $245,000 over a 24-month period, or $122,500, for the cleaning of Kentucky River Station I's lagoon in June 2011.[105] Kentucky-American developed its forecasted cost by averaging the three lowest bids received for lagoon cleaning in 2009.[106]

The AG offers two alternative methods to the forecasted expense. AG witness Smith argues that the most appropriate means to forecast the expense is to average the actual costs of the four lagoon cleanings that have occurred since 2001. He proposes an annual cost of $90,000, which is the average cost of the last four lagoon cleanings, amortized over 24 months.[107] The AG also suggests that this expense be based upon the lowest bid that Kentucky-American received for lagoon cleaning conducted in

[103] Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), WP 3-3.

[104] Kentucky-American's Response to Hearing Data Requests, Item 7, at 1.

[105] Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), WP 3-4.

[106] Rebuttal Testimony of Keith Cartier at 2.

[107] Public Direct Testimony of Ralph C. Smith at 76-77.

2009.[108] This methodology produces the same result as AG witness Smith recommends.

Noting that AG witness Smith's methodology requires the use of dated and potentially inaccurate information, Kentucky-American opposes the proposed adjustment. Kentucky-American witness Cartier testified that lagoon cleaning occurs approximately every three years. Relying on the average cost of the four prior lagoon cleanings as the AG recommends requires reliance on some cost information that is at least twelve years old and that does not consider the effects of inflation or changing market conditions.[109]

The Commission finds that Kentucky-American's methodology for forecasting lagoon cleaning expense is reasonable and further finds that the AG's proposed methodology, as it fails to consider the effects of inflation and relies upon dated information, is inappropriate. Accordingly, we decline to accept the AG's proposed adjustment to Kentucky-American's forecasted waste disposal expense.

Management Fees. Kentucky-American has included management fee expense of $9,028,121 in its forecasted operations.

---

[108] AG's Brief at 28.

[109] Rebuttal Testimony of Keith Cartier at 1-2.

• Revised Service Company Budget. The AG proposes to decrease forecasted management fees by $133,865 to reflect adjustments in the Service Company's budget.[110] Kentucky-American does not contest the proposed adjustment.[111] Kentucky-American informed the Commission that its forecasted management fee should be reduced by $133,865 to reflect a revision to the Service Company budget that had been finalized after the application in this proceeding had been filed. Accordingly, the Commission has decreased Kentucky-American's forecasted management fee by $133,865 to reflect the updated actuarial information.

• ICP and Stock-based Compensation. Included in Kentucky-American's management fee forecast is incentive compensation of $436,987 and stock-based compensation of $179,208. For reasons previously stated,[112] the Commission finds that Kentucky-American's forecasted management fee should be decreased by $616,195 to eliminate the ICP and stock-based compensation plan.

• Donations and Miscellaneous Expenses. The AG proposes a reduction of $65,793 in management fees to eliminate charitable contributions, advertising, dues and other miscellaneous expenses.[113]

Kentucky-American opposes the proposed adjustment as it relates to advertising expenses, membership dues, and employee meals. As to the proposed removal of

---

[110] Public Direct Testimony of Ralph C. Smith, Exhibit RCS-1, Schedule C-6.

[111] Rebuttal Testimony of Michael A. Miller at 47-48.

[112] *See supra* text accompanying notes 89-99.

[113] Public Direct Testimony of Ralph C. Smith at 56-58; Exhibit RCS-1, Schedule C-8.

advertising expenses of $11,909, Kentucky-American witness Michael Miller testified that these expenses consisted primarily of job placement ads and are related to recruitment and hiring efforts to maintain adequate personnel staffing.[114] As to the membership fees of $23,961,[115] which include memberships for Service Company employees in the American Bar Association, American Water Works Association, Kentucky Bar Association, and American Institute of Certified Public Accountants, Kentucky-American asserts that the memberships are necessary to ensure professional certification for the Service Company employees and to ensure these employees have access to valuable and pertinent information in their respective fields and the water industry and, therefore, benefit ratepayers.[116] Finally, Kentucky-American notes that it and the Service Company have policies prohibiting reimbursement for any meals except those having a legitimate business purpose and the meals in question complied with those policies.

The Commission finds that the expenses at issue that are related to advertising expenses, membership dues, and employee meals should not be disallowed or excluded. The record contains substantial evidence that each is for legitimate purposes. The AG has presented no evidence to support a contrary finding. We find the advertising expenses in question relate to a legitimate business function and provide a material benefit to Kentucky-American customers. We further find that recovery of

[114] Rebuttal Testimony of Michael A. Miller at 53.

[115] For a list of these organizations, see Kentucky-American's Response to AG's First Request for Information, Item 1a.

[116] *Id.*

fees related to an employee's membership in a professional organization is generally appropriate and beneficial to ratepayers in those instances in which the employee's membership is required to comply with professional licensing requirements or provides the employee access to technical training and assistance in specialized areas involving utility management or operations.

As to the other items that the AG has identified, the Commission finds those expenses are not appropriately borne by ratepayers and that Kentucky-American's forecasted management fee should be decreased by $9,735[117] to reflect their removal.

- Business Development. In its forecasted management fee, Kentucky-American includes business development costs of $223,380 that the Service Company has allocated to Kentucky-American. Of this amount, the Commission has deducted $23,834 to reflect the elimination of costs related to AIP or stock-based compensation.[118]

AG witness Smith proposes a further reduction of business development costs of $198,342. He contends that these expenses are "unnecessary for the provision of safe, reliable and reasonably priced water and wastewater utility service in Kentucky."[119] In his brief, the AG argues that business development advances the interest of shareholders and that such activity contains no assurance or certainty of benefits for Kentucky-American ratepayers. Until Kentucky-American has demonstrated a clear

---

[117] $4,728 (Charitable Contributions) + $3,499 (Community Relations) + $1,427 (Company Dues Membership) + $81 (Penalties) = $9,735.

[118] *See supra* text accompanying notes 86-96; Public Direct Testimony of Ralph C. Smith, Exhibit RCS-1, Schedule C-7.

[119] Public Direct Testimony of Ralph C. Smith at 56.

benefit to ratepayers, he further argues, these costs should not be assigned to ratepayers.

Opposing the proposed adjustment, Kentucky-American contends the proposal is unsupported and contrary to the existing evidence. It notes that AG witness Smith made no effort to determine what comprises business developments costs and has not performed an independent analysis to determine if the ratepayers benefited from those activities.[120] It further contends that Kentucky-American's existing customers benefit from the revenue growth produced from development activities and from efficiency gains, cost-saving measures and growth that acquisitions spur. It noted that Kentucky-American's recent contract to perform billing services for LFUCG will provide $364,000 in annual revenues and will benefit ratepayers by reducing Kentucky-American's revenue requirement.[121]

The Commission has previously placed Kentucky-American on notice that business development expenses allocated to the utility from the Service Company would be considered reasonable and appropriate for rate recovery only in those instances in which the utility was able to "appropriately document and separate forecasted management fees between those that are directly assignable and those that are allocated."[122] In the present proceeding, the Commission sought a detailed listing and description of business development costs included in forecasted management

[120] Rebuttal Testimony of Michael A. Miller at 51.

[121] *Id.* at 51-52.

[122] Case No. 2004-00103, Order of Feb. 28, 2005, at 53. Placing this burden upon Kentucky-American is consistent with Kentucky-American's statutory duty as an applicant to demonstrate that its proposed rates are reasonable. *See* KRS 278.190(2).

fees. Kentucky-American provided a breakdown of the business development costs by object account but could not describe the business development services that would be provided for each identified cost.[123]

In light of its failure to identify or describe the business development services that the Service Company provides, we find that Kentucky-American has failed to meet its burden to demonstrate the reasonableness of the business development expenses and that the AG's proposed adjustment to reduce forecasted management fees by $198,342 should be accepted.

- Employee Transfer. To reflect the transfer of three employees from Kentucky-American to the Service Company, Kentucky-American proposes to increase management fees by $370,765.[124] The Commission finds that Kentucky-American's forecasted management fee should be increased by $370,765 to reflect the transfer of three Kentucky-American employees to the Service Company.

- Labor Costs. LFUCG witness Baudino proposes a reduction of $2,146,000 in management fee expense to eliminate the labor allocations that Kentucky-American has failed to show were prudently incurred. He testified that Kentucky-American's application indicates that the Service Company labor costs are greater than if no reorganization or restructuring of Kentucky-American and the Service

[123] Kentucky-American's Response to Commission Staff's Second Information Request, Item 20(c).

[124] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT).

Company had occurred and that none of the stated benefits of the restructuring justify the greater level of costs.[125]

The Commission finds that LFUCG has not provided sufficient evidence to support the proposed adjustment. In his testimony, Mr. Baudino provides little justification or factual evidence to support his position. Moreover, he ignores the previously filed testimony of Kentucky-American witness Baryenbruch, who testified extensively on the benefits that the Service Company provides to Kentucky-American and who concluded that Kentucky-American's arrangement with the Service Company resulted in a savings of $1.5 million to Kentucky-American and its ratepayers. In light of the absence of any attempt to contradict or rebut Mr. Baryenbruch's findings, we afford little weight to Mr. Baudino's testimony on this issue and decline to make the proposed adjustment.

Group Insurance. Kentucky-American included in its forecasted operations group insurance expense of $2,313,543.[126] The forecasted expense is comprised of group insurance costs for the current associates and post-retirement employee benefit costs ("OPEB") for Kentucky-American's current and retired employees. Kentucky-American based OPEB expense upon the projections of the actuarial firm of Towers Watson. The current group insurance costs reflect the use of Kentucky-American's current group insurance premium statement rates in effect as of January 1, 2010.[127] After filing its application, Kentucky-American proposed to decrease forecasted group

---

[125] Direct Testimony of Richard A. Baudino at 44-46.

[126] Application, Exhibit 37, Schedule C-2.

[127] Direct Testimony of Sheila A. Miller at 5-6.

insurance by $52,206[128] to reflect the latest Towers Watson actuarial projections for the forecasted test year[129] and by an additional $47,202[130] to reflect the transfer of three employees to the Service Company.[131] Group insurance expense has been decreased by an additional $65,247 to reflect the elimination of projected employee wage increases. The Commission finds that these proposed adjustments are reasonable and that Kentucky-American's forecasted group insurance expense should be decreased by $164,835.

Pension. Kentucky-American includes pension expense of $1,267,732 in its forecasted operations.[132] Towers Watson's projected pension costs are allocated to each of AWWC's subsidiaries based upon the ratio of valuation earnings for that company to total valuation earnings for AWWC.[133] After filing its application, Kentucky-American proposed to decrease forecasted pension expense by $253,262 to reflect

---

[128] Kentucky-American's Response to Commission Staff's Second Information Request, Item 23.

[129] Rebuttal Testimony of Michael A. Miller at 38; Kentucky-American's Response to Commission Staff's Second Request for Information, Item 23; Kentucky-American's Response to AG's Second Request for Information, Item 67(e).

[130] $42,300 (Group Insurance) + $3,995 (401(k) + $846 (DCP) + $61 (Retiree Medical) = $47,202.

[131] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT).

[132] Direct Testimony of Michael A. Miller at 28.

[133] KAWC's Response to Commission Staff's First Information Request, Item 1(a) Workpaper WP3-7, at 3.

Towers Watson's most recent projections[134] and by an additional $56,027 to reflect the transfer of the three employees to the Service Company.[135] Pension expense has been decreased by an additional $29,407 to reflect the elimination of the employee wage increases. The Commission finds that these proposed adjustments are reasonable and that Kentucky-American's forecasted pension expense should be decreased by $340,751.

Regulatory Expense. Kentucky-American includes regulatory expense of $366,462 in its forecasted operations.[136] This forecasted expense includes the cost of its depreciation study, amortized over a five-year period; the preparation and litigation costs of the present case,[137] amortized over a three-year period; and the amortized rate case expenses associated with its previous two rate cases. Since filing its application, Kentucky-American has proposed to adjust the forecasted level to $391,328 to correct its failure to include the final two months of amortization of rate case expenses for Case No. 2007-00143.[138] Following the evidentiary hearing in this matter, Kentucky-American

---

[134] Rebuttal Testimony of Michael A. Miller at 38; Kentucky-American's Response to Commission Staff's Second Request for Information, Item 23.

[135] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT).

[136] Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), W/P 3-8, at 1; Rebuttal Testimony of Michael A. Miller at 38-39.

[137] Kentucky-American originally projected the level of this expense at $590,000. Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), W/P 3-8, at 2.

[138] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT); Kentucky-American's Response to AG's Second Request for Information, Item 69(e).

revised its forecast of preparation and litigation costs of the present case to $553,121, which is $36,879 below its original projection.[139]

The AG objects to the inclusion of all rate case expenses associated with Cases No. 2007-00143 and No. 2008-00426. He notes that in neither proceeding did the Commission make a finding regarding the reasonableness of these expenses, expressly authorize their recovery through general rates, or authorize Kentucky-American to record the costs as regulatory assets. Furthermore, the AG contends, as both cases involved settlement agreements which were silent on the recovery of rate case expenses, Kentucky-American's current efforts to recover the rate case expenses constitute an attempt to unilaterally amend the settlement agreements in those proceedings.[140]

Responding to the AG's objection, Kentucky-American argues that longstanding Commission precedent supports the practice of amortizing over a three-year period reasonably incurred rate case expenses.[141] It has provided evidence that the expenses in question were incurred in the course of preparing for and litigating rate case proceedings. It further notes that the AG has presented no evidence in this proceeding to suggest that the expenses in question were not incurred or were unreasonable. While the issues in Cases No. 2007-00147 and No. 2008-00426 were resolved by settlement agreements that were silent on the issue of rate case expenses, Kentucky-American notes, no party in those proceedings contested Kentucky-American's

---

[139] Kentucky-American's Response to Hearing Data Requests, Item 20.

[140] AG's Brief at 15-16; Public Direct Testimony of Ralph C. Smith at 60-61.

[141] Kentucky-American's Brief at 36 & n.49.

recovery of rate case expenses through general rates. It is unreasonable, Kentucky-American asserts, that shareholders should bear the full cost of these rate cases because those cases ended in agreement.[142]

It is a well-settled principle of utility law that rate case expenses "must be included among the costs of operation in the computation of a fair return."[143] Kentucky-American, however, has presented no evidence to demonstrate that the rates agreed to and approved in Cases No. 2007-00147 and No. 2008-00426 failed to include rate case expense. As the settlement agreement in each proceeding is silent on this issue, we cannot assume that parties agreed to the amortization of rate case expense any more than we can assume that parties did not establish rates providing for the immediate expensing of the full rate case expense. Accordingly, we find that the AG's proposed adjustment should be accepted.

Any utility that enters a settlement agreement in a rate case proceeding and wishes to amortize the rate case expense incurred in that proceeding should ensure that the settlement agreement specifically addresses the issue of rate case expenses <u>or</u> request the creation of a regulatory asset for its rate case expenses for accounting purposes. Such practice is consistent with our prior holdings that the establishment of a regulatory asset for accounting purposes is a pre-condition for rate recovery in a later

---

[142] Rebuttal Testimony of Michael A. Miller at 43.

[143] *West Ohio Gas Co. v. Public Utilities Comm'n*, 294 U.S. 63, 74 (1935).

rate case proceeding and that the Commission's prior approval is necessary before the establishment of a regulatory asset.[144]

The AG further proposes a 30.4 percent reduction of Kentucky-American's forecasted rate case expense amortization amount for the current case. He asserts that Kentucky-American has consistently overstated its forecasted rate case expenses. He proposes to normalize the current estimated rate case expense using the ratio of actual costs to projected costs from Kentucky-American's last two general rate case proceedings.[145]

For several reasons, we find no merit in this proposal. First, the Commission has historically used actual costs to determine rate case expense, even in proceedings in which a forward-looking test period is used. This practice ensures greater accuracy than the normalization method that the AG proposes. Second, the rate case proceedings which the AG uses to develop his normalization ratio ended with settlement agreements and truncated hearings. Those proceedings generally do not require extensive hearing preparation or the preparation of written briefs and hence the level of expense incurred in them is generally much less than fully contested rate case proceedings. Third, normalization implicitly assumes that all rate cases are roughly equivalent. In practice, the number and complexity of issues, the intensity of discovery, and the number of parties in a proceeding, all factors affecting rate case expense, may significantly vary. Fourth, as normalization generally involves an average of historical

[144] *See, e.g.*, Case No. 2003-00426, Application of Louisville Gas and Electric Company for an Order Approving an Accounting Adjustment to Be Included in Earnings Sharing Mechanism Calculations for 2003, at 4 (Ky. PSC Dec. 23, 2003).

[145] Public Direct Testimony of Ralph C. Smith, Exhibit RCS-1, Schedule C-11.

costs, it will not reflect inflationary increases in the legal, accounting and other costs that are incurred in preparing and litigating a rate case proceeding.

The AG has further proposed that we abandon our long-standing practice of amortizing rate case expense and, instead, normalize that expense. Through normalization, Kentucky-American would be entitled to recover not the historical amount of the expenditure but a future amount that the Commission deems reasonable. Much like amortized historical amounts, the normalized costs would be divided by their estimated useful lives to determine the annual expense to be recovered through rates.

The AG asserts that the normalization approach would eliminate the unamortized account balances since those accounts would no longer be recorded on Kentucky-American's books. He asserts that "the purpose of the rate case allowance should be to include in rates a representative and normal annual level of reasonably and prudently incurred regulatory expense, rather than to provide the utility with a single-issue focus and what could otherwise become a guaranteed dollar-for-dollar recovery for this cost."[146]

The AG's arguments closely resemble those that he presented in Case No. 2004-00103. For the same reasons set forth in our decision in that proceeding, we decline to follow the AG's suggested course of action.[147] Based upon our review of the record, we find that forecasted regulatory expense should be decreased by $148,128, from $391,328 to $243,200, to reflect the elimination of amortized rate case expense

[146] *Id.* at 66.

[147] Case No. 2004-00103, Order of Feb. 28, 2005, at 20.

from Cases No. 2007-00143[148] and No. 2008-00426, and the reduction of $12,293 of amortized rate case expense related to the current proceeding.[149]

Insurance Other Than Group. Kentucky-American includes in its forecasted operations insurance other than group expense of $742,262.[150] This forecast reflects the current annual premiums for the following insurance coverages: general liability; property liability; fiduciary liability; commercial crime coverage; flood liability; and worker's compensation. Kentucky-American proposed to reduce its forecast by $47,931 to reflect the 2010 insurance premiums and by an additional $804 to reflect the transfer of three Kentucky-American employees to the Service Company.[151] The Commission finds that the proposed adjustments are reasonable and that forecasted insurance other than group expense should be decreased by $48,735.

Customer Accounting. Kentucky-American includes customer accounting expense of $1,712,517 in its forecasted operations.[152] This expense includes, but is not

---

[148] The only cost included from Case No. 2007-00143 is $6,000 for the 2007 depreciation study.

[149] $590,000 (original forecast) - $553,121 (revised forecast) = $36,879.
$36,879 ÷ 3-years = $12,293 (reduction in amortized rate case expenses).

[150] Application, Exhibit 37, Schedule C-2; Direct Testimony of Sheila A. Miller at 7.

[151] E-mail from Lindsey Ingram III, Kentucky-American counsel, to Gerald Wuetcher, Commission Staff counsel (Sep. 15, 2010, 14:39 EDT); Rebuttal Testimony of Sheila A. Miller at 4; Base Period Update Filing, Exhibit 37, Schedule D-2.3 (filed July 15, 2010).

[152] Direct Testimony of Sheila A. Miller at 7; Application, Exhibit 37, Schedule C-2.

limited to the following: postage; telephone; forms for customer service and billing; uncollectible accounts; and collection agencies.[153]

The AG proposes to reduce uncollectible accounts by $27,580.[154] He notes that Kentucky-American did not use budget information to develop its forecasted uncollectible expense, but instead developed an "Uncollectibles Factor" based upon the ratio of its 2009 uncollectible expense to its billed revenue and then applied this factor to pro forma revenues for the forecasted test year.[155] This factor is significantly higher than the Uncollectible Factor for most recent years. As the "Uncollectibles Factor" fluctuates, AG witness Smith argues, it is more appropriate to use a three-year average rather than place undue reliance upon any one year.[156]

Kentucky-American did not directly respond to AG witness Smith's proposed adjustment. In a response to a discovery request, however, it stated that its "experience for 2009 was the best indicator of the uncollectible expense likely to be present in the forecasted test-year in this case, given the current and expected economic conditions during the forecasted test-year."[157] In his rebuttal testimony, Kentucky-American

---

[153] Direct Testimony of Sheila A. Miller at 7.

[154] Direct Testimony of Ralph C. Smith at 80.

[155] *Id.* at 78-79.

[156] *Id.*

[157] Kentucky-American's Response to Commission Staff's Third Request for Information, Item 7.

witness Michael Miller noted that the AG's proposal was an acceptable method of rate-making.[158]

Based upon our review of the evidence, we find that Kentucky-American has failed to demonstrate that its proposed method of forecasting uncollectible accounts is reasonable and that the AG's proposed methodology is reasonable and more appropriate in this case. Accordingly, we accept the AG's adjustment to reduce Kentucky-American's forecasted customer accounting expense by $27,589 to reflect the average uncollectible rate of 0.741 percent.

Miscellaneous Expense. Kentucky-American includes general office expense of $3,440,139 in forecasted operations.[159] This expense includes, but is not limited to the following: dues and memberships; employee travel and meal expenses; office supplies; and general office utility costs.[160] Kentucky-American includes the following in this expense: $14,420 for an employee recognition banquet; $5,150 for a United Way rally; and $5,500 for a holiday event.[161]

The AG proposes to reduce miscellaneous expense by $25,070 to remove the three specific expenses listed above.[162] He contends that none of the expenses are

---

[158] Rebuttal Testimony of Michael A. Miller at 33 ("As Mr. Smith suggests regarding uncollectible expense, you can use an average, or adjust based on historical actual to budget much like the Commission historically treats forecasted test-year capital spending.").

[159] Application, Exhibit 37, Schedule C-2; Direct Testimony of Sheila A. Miller at 8.

[160] Direct Testimony of Sheila A. Miller at 8.

[161] Application, Exhibit 37, Schedule F-2.3.

[162] Public Direct Testimony of Ralph C. Smith at 71.

necessary to provide safe, adequate and proper utility service and are more properly borne by utility shareholders.

Contending that the expenses are appropriate and benefit utility customers, Kentucky-American opposes the proposed reduction. It asserts that its employee recognition banquet is an appropriate means of recognizing employees' contributions and enhances customer service and satisfaction by promoting a cohesive and motivated work force. The United Way, it argues, promotes employee participation and contribution in an important community program that directly benefits many of the company's customers.[163]

In prior rate case proceedings, the Commission has found that the costs related to employee recognition banquets and gifts should not be borne by utility ratepayers.[164] As to the United Way function, while the community and thus Kentucky-American's customers indirectly receive some benefit from the function, the expense is a form of charitable contribution which the Commission has generally found should be borne by utility shareholders.[165] Accordingly, we accept the AG's proposed adjustment.

Depreciation. Kentucky-American includes depreciation expense of $11,086,076 in its forecasted operations.[166] Based on the Commission's treatment of forecasted rate base with regard to slippage and the effect of revisions to Kentucky-American's

---

[163] Rebuttal Testimony of Michael A. Miller at 72.

[164] *See, e.g.*, Case No. 97-034, Order of Sep. 30, 1997, at 40; Case No. 95-554, Order of Sep. 11, 1996, at 43.

[165] *See, e.g.*, Case No. 95-554, Order of Sep. 11, 1996, at 43.

[166] Application, Exhibit 37, Schedule I-1; Kentucky-American's Response to Commission Staff's First Request for Information, Item 1(a), W/P 4-1, at 9.

depreciation study, an adjustment has been made to decrease forecasted depreciation expense by $201,593.[167]

General Taxes. Kentucky-American includes a forecast of general tax expense of $5,160,307, which includes property taxes and payroll taxes of $4,419,174 and $621,307. Based on our treatment of forecasted rate base with regard to slippage, we have increased forecasted property taxes expense by $15,539. We have also reduced payroll taxes by $63,473 to reflect the effects of our removal of the costs of incentive pay plans, the elimination of the employee wage increases, and the transfer of three Kentucky-American employees to the Service Company.

Income Taxes. Kentucky-American includes a forecast of current income tax expense of $1,066,982 in test-period operations. Adjusting Kentucky-American's income tax forecast, the Commission arrives at its current income tax expense of $23,182 as shown in Table III.

---

[167] $60,553 (Slippage Adjustment) + ($262,146) (Depreciation Study Revision) = ($201,593).

Table III: Current Income Tax				
	Adjustments	Income Taxes		
	Revenue/ Expense	State 6.0000%	Federal 35.0000%	Total
KAWC's Forecasted Taxes		$ (164,573)	$ (902,409)	$(1,066,982)
AFUDC	$ (44,094)	(2,646)	(14,507)	(17,153)
Labor	$ (803,586)	48,215	264,380	312,595
Fuel & Power - 11.8% Line Loss	$ (77,997)	4,680	25,661	30,341
Chemicals - 11.8% Line Loss	$ (43,653)	2,619	14,362	16,981
Management Fees	$ (587,372)	35,242	193,246	228,488
Group Insurance	$ (164,835)	9,890	54,231	64,121
Pensions	$ (340,751)	20,445	112,107	132,552
Regulatory Expense	$ (160,421)	9,625	52,779	62,404
Insurance Other than Group	$ (48,735)	2,924	16,034	18,958
Customer Accounting	$ (27,589)	1,655	9,077	10,732
Miscellaneous	$ (25,070)	1,504	8,248	9,752
Depreciation - Slippage	$ (201,593)	12,096	66,324	78,420
Property & Capital Stock	$ 15,539	(932)	(5,112)	(6,044)
Payroll	$ (63,473)	3,808	20,883	24,691
Interest Synchronization	$ (89,181)	5,351	29,341	34,692
Book Depreciation	$ (60,553)	3,633	19,922	23,555
Tax Depreciation	$ 138,010	(8,281)	(45,405)	(53,686)
Taxable Customer Advances & CIAC	$ (263,660)	15,820	86,744	102,564
Tax AFUDC	$ (41,651)	2,499	13,703	16,202
		$ 3,574	$ 19,609	$ 23,183

Consolidated Income Tax Adjustment. The AG proposes that Kentucky-American's forecasted current and deferred income tax expenses be adjusted to reflect the use of a consolidated tax return. He notes that Kentucky-American calculates federal income taxes on a stand-alone basis.[168] Kentucky-American, however, is part of a consolidated group, which AWWC owns, that files a combined federal income tax return to take advantage of the tax losses experienced by some of the group's members.[169] The use of a consolidated tax filing, the AG states, permits the tax loss benefits generated by one group of subsidiaries to be shared by the other consolidated

[168] AG's Brief at 7; Public Direct Testimony of Ralph C. Smith at 29.

[169] Public Direct Testimony of Ralph C. Smith at 29-30.

group members, thus resulting in a reduced effective federal income tax rate. The AG proposes that these tax benefits should be flowed to Kentucky-American's ratepayers to reflect the actual taxes paid rather than calculate the amount of taxes based upon stand-alone methodology. To do otherwise, he argues, would overstate Kentucky-American's federal income tax. Regulatory commissions in three other jurisdictions in which AWWC affiliates are located have adopted consolidated tax adjustments for rate-making purposes.[170] Use of the AG's consolidated tax adjustment results in a decrease of $1,361,624 to Kentucky-American's forecasted income tax expense.[171]

The AG's proposed adjustment relies heavily upon our decision in Case No. 2004-00103 in which we found the use of a consolidated tax adjustment was warranted and appropriate in view of representations that Kentucky-American, AWWC and RWE Aktiengesellschaft ("RWE") had made in an earlier proceeding[172] to secure Commission approval of RWE's acquisition of control of Kentucky-American and the conditions that we had imposed as part of our approval. We stated in that decision:

> In that proceeding [Case No. 2002-00317], Kentucky-American and others sought approval of the transaction that enabled RWE's acquisition of control of Kentucky-American. One feature of this transaction was the creation of TWUS [Thames Water Aqua US Holdings, Inc.], an intermediate holding company that would hold the stock of American

[170] These jurisdictions are Pennsylvania, New Jersey, and West Virginia. Oregon and Texas also impose a consolidated tax adjustment. Rebuttal Testimony of James I. Warren at 24.

[171] Public Direct Testimony of Ralph C. Smith, Schedule C-2.

[172] Case No. 2002-00317, The Joint Petition of Kentucky-American Water Company, Thames Water Aqua Holdings GmbH, RWE Aktiensgeselschaft, Thames Water Aqua US Holdings, Inc., Apollo Acquisition Company and American Water Works Company, Inc. for Approval of a Change of Control of Kentucky-American Water Company (Ky. PSC Dec. 20, 2002).

> Water and all of Thames Water Aqua Holdings GmbH's other U.S. affiliates. Kentucky-American asserted the creation of TWUS would permit the filing of consolidated U.S. tax returns. The ability to file such a tax return, Kentucky-American argued, benefited the public because it would reduce administrative expenses by eliminating the need to file multiple tax returns and permit some tax savings by allowing payment of taxes calculated on the net profits of all entities within the consolidated group.
>
> We note that when approving the proposed transaction, we rejected specific proposals to condition our approval on the Joint Petitioners treating any tax savings achieved through the write-off of losses incurred in unregulated U.S. operations against regulated U.S. earnings as a benefit of the transaction and sharing that benefit with Kentucky-American ratepayers. We took that action, not because the proposals were without merit, but because we had previously directed that a portion of any merger savings be allocated to Kentucky-American ratepayers and that additional conditions were unnecessary. Kentucky-American did not take exception to or protest our reasoning.
>
> Having previously indicated the savings resulting from the filing of a consolidated tax filing would be viewed as a merger benefit, subject to allocation, we do not believe that acceptance of the AG's proposal represents a radical departure from past regulatory practice. Moreover, Kentucky-American and its corporate parents having previously touted TWUS's filing of consolidated tax returns as a benefit to obtain approval of the merger transaction, have no cause to object if we now act upon their representation.[173]

RWE's recent divestiture of AWWC, however, significantly limits the application of the holding in Case No. 2004-00103. In approving the proposed divestiture, the Commission expressly declared that all terms and conditions imposed as part of our

---

[173] Case No. 2004-00103, Order of Feb. 28, 2005, at 64-66. In the current proceeding, Kentucky-American argues that the Commission misunderstood and misinterpreted RWE and AWWC's representations regarding potential tax savings related to the transaction before us in Case No. 2002-00317. Our review of the record of Case No. 2002-00317 indicates considerable merit to Kentucky-American's position.

approval of RWE's acquisition of control of Kentucky-American would terminate upon RWE's complete divestiture of its interests in AWWC.[174] That divestiture occurred on November 30, 2009.[175] To the extent that the Commission has based the use of a consolidated tax adjustment on the premise that any savings resulting from the TWUS's use of a consolidated tax return was a benefit of the RWE acquisition and should be shared with ratepayers, the RWE divestiture renders that premise invalid.

Except for Case No. 2004-00103, which involves unique circumstances, the Commission has consistently rejected proposals to apply a consolidated tax adjustment and treated utilities on a stand-alone basis.[176] We have found that use of such an adjustment would result in the subsidization of ratepayers by the utility's non-regulated operations. Moreover, many utility regulatory commissions appear to disfavor

---

[174] Case No. 2006-00197, The Joint Petition of Kentucky-American Water Company, Thames Water Aqua Holdings GmbH, RWE Aktiengesellschaft, Thames Water Aqua U.S. Holdings, Inc., and American Water Works Company, Inc. for Approval of a Change In Control of Kentucky-American Water Company, at 36 (Ky. PSC April 16, 2007).

[175] *See* Case No. 2009-00359, Kentucky-American Water Company's Application for Approval of Payment of Dividend for Third Quarter of Calendar Year 2008 (Ky. PSC Dec. 28, 2009).

[176] *See, e.g.*, Case No. 2009-00549, Application of Louisville Gas and Electric Company for an Adjustment of Electric and Gas Rates (Ky. PSC July 30, 2010); Case No. 2009-00548, Application of Kentucky Utilities Company for an Adjustment of Electric Rates (Ky. PSC July 30, 2010); Case No. 2003-00434, An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Louisville Gas and Electric Company (Ky. PSC June 30, 2004); Case No. 2009-00548, An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Kentucky Utilities Company (Ky. PSC June 30, 2004).

the use of consolidated tax adjustments.[177] In light of the RWE divestiture and the absence of any compelling argument to jettison the "stand-alone" rate-making principle, we find that the AG's proposed income tax consolidation adjustment should be denied.

Deferred Income Taxes. Kentucky-American includes a forecast of deferred income tax expense of $2,177,869 in test-period operations. Adjusting Kentucky-American's income tax forecast for slippage, the tax-exempt financing, and the revision of the depreciation study, the Commission arrives at a deferred income tax expense of $2,328,717.

Based on the accepted adjustments to forecasted revenues and expenses, the Commission finds Kentucky-American's forecasted net operating income at present rates to be $16,441,382 as shown in Table IV.

Table IV: Income Statement Comparison

Account Titles	Kentucky-American Forecasted Revenues & Expenses	Recommended Adjustments	Forecasted Revenues & Expenses
OPERATING REVENUES			
Water Sales	$ 64,753,488	$ -	$ 64,753,488
Other Operating Revenues	3,770,137	(44,094)	3,726,043
Operating Revenues	$ 68,523,625	$ (44,094)	$ 68,479,531
OPERATING EXPENSES			
Operation & Maintenance Exp.	$ 35,459,367	$ (2,280,009)	$ 33,179,358
Depreciation & Amortization	11,319,797	(201,593)	11,118,204
General Taxes	5,160,307	(47,934)	5,112,373
Income Tax Expense	1,110,887	1,241,012	2,351,899
Total Operating Expenses	$ 53,050,358	$ (1,288,524)	$ 51,761,834
Net Operating Income	$ 15,473,267	$ 1,244,430	$ 16,717,697

[177] *See, e.g., Re SourceGas Distribution LLC*, 280 PUR 4th 226 (Neb. PSC Mar. 9, 2010); *Re Delmarva Power and Light Company*, 278 PUR4th 419 (Md. PSC Dec. 30, 2009); *Washington Utilities and Transportation Commission v. PacifiCorp dba Pacific Power & Light Co.*, 257 PUR4th 380 (Wash. UTC June 21, 2007); *Northern States Power Company dba Xcel Energy*, 253 PUR4th 40 (Minn. PUC Sep. 1, 2006); *Re Ohio Bell Telephone Company*, 8 PUR3d 136 (Ohio PUC Dec. 30, 1954).

Rate of Return

Capital Structure. Kentucky-American's proposed capital structure based on the projected 13-month average balances for the forecasted test period and the costs assigned to each capital component is shown in Table V.

TABLE V		
Components	Kentucky-American's Capitalization	Assigned Costs
Short-Term Debt	2.315%	2.085%
Long-Term Debt	52.060%	6.410%
Preferred Stock	1.652%	7.750%
Common Equity	+ 43.973%	11.500%
Total Capitalization	100.000%	

Although the AG states that he is employing Kentucky-American's proposed capital structure in developing his recommended weighted cost-of-capital,[178] the actual capital structure that he uses is shown in Table VI.

TABLE VI		
Components	AG's Capitalization	Assigned Costs
Short-Term Debt	2.32%	0.63%
Long-Term Debt	52.06%	6.32%
Preferred Stock	1.65%	7.75%
Common Equity	+ 43.97%	9.25%
Total Capitalization	100.000%	

The Commission is adjusting Kentucky-American's capital structure as shown in Table VII.

[178] Direct Testimony of J. Randall Woolridge at 13.

TABLE VII

	Short-Term Debt	Long-Term Debt	Preferred Stock	Common Equity	Total Capital
Proposed Capital Structure	$ 8,319,538	$187,073,668	$ 5,935,810	$158,013,385	$359,342,401
Slippage Adjustment	1,249,182	(1,448)	(52)	(1,315)	1,246,367
Working Capital AIP Days	(458,956)	571	18	484	(457,883)
Deferred Compensation	185,788	(234)	0	(190)	185,364
Tax Exempt Financing	(11,214)	9	9	9	(11,187)
Capital Structure	$ 9,284,338	$187,072,566	$ 5,935,785	$158,012,373	$360,305,062
Capital Rates	2.577%	51.921	1.647%	43.855%	100.000%

Short-Term and Long-Term Debt. Kentucky-American originally projected short-term and long-term interest rates of 2.085 percent and 6.41 percent, respectively.[179] It subsequently revised its original projections to reflect the current financial market conditions, which results in short-term and long-term interest rates of 1.90 percent and 6.38 percent, respectively.[180] Using its analysis of the current federal funds rate, the AG proposed short-term and long-term interest rates of 0.63 percent and 6.32 percent, respectively.[181] Upon review of the supporting calculations, the Commission finds that Kentucky-American's revised projections result in a more current projection of the forecasted debt rates. For this reason, we find the proposed cost of debt is reasonable and should be accepted.

[179] Direct Testimony of Michael A. Miller, Exhibit MAM-3.

[180] Rebuttal Testimony of Michael A. Miller at 6 and Rebuttal Exhibit MAM-1; Base Period Update Filing, Exhibit 37, Schedule J-3 (filed July 15, 2010).

[181] Direct Testimony of J. Randall Woolridge at 14.

Preferred Stock. Kentucky-American proposed an embedded cost of preferred stock of 7.75 percent.[182] No party objected to this forecasted cost rate. We find that the proposed embedded cost of preferred stock is reasonable and should be accepted.

Return on Equity. Kentucky-American recommends a return on equity ("ROE") ranging from 10.8 percent to 12.1 percent and specifically requests an ROE of 11.5 percent based on its discounted cash flow model ("DCF"), the ex ante risk premium method, the ex post risk premium method, and Capital Asset Pricing Model ("CAPM").[183]

To perform its analysis, Kentucky-American witness Vander Weide employed two comparable risk proxy groups in its analysis. The first proxy group consists of eleven water companies included in the *Value Line Investment Survey* ("*Value Line*") that: pay dividends; did not decrease during any quarter for the past two years; have at least one analyst's long-term growth forecast; and are not part of an ongoing merger. All of these water companies have a *Value Line* Safety Rank of at least 3, which is the average of all *Value Line* companies.[184]

Dr. Vander Weide's second proxy group consisted of twelve natural gas local distribution companies. Each company was in the natural gas distribution business; paid quarterly dividends over the last two years; had not decreased dividends over the last two years; was not involved in an ongoing merger, and had at least two analysts'

---

[182] Application, Exhibit 37, Schedule J-1.

[183] Direct Testimony of Michael A. Miller at 15; Direct Testimony of James H. Vander Weide at 3-4.

[184] *Id.* at 22-23.

estimates of long-term growth included in the I/B/E/S consensus growth forecast.[185] Each also had a *Value Line* Safety Rank of 1, 2 or 3 and an investment grade bond rating.[186]

Dr. Vander Weide applied a quarterly DCF model to the water company and gas proxy groups. He relied upon the gas company proxy group solely for the ex ante risk premium ROE estimation. He relied upon Standard & Poor's ("S&P") 500 stock portfolio and the S&P Public Utility Index to derive the ex post risk premium ROE estimation. Though Dr. Vander Weide performed CAPM analyses using both proxy groups, he did not rely upon the CAPM estimations in reaching his recommended ROE. He rejected the CAPM analyses because the average beta coefficient for the proxy companies was significantly below a value of 1 and because several of the water companies have relatively low market capitalization.[187] As part of his ROE recommendations, Dr. Vander Weide also made adjustments for flotation costs.

AG witness Woolridge takes issue with several aspects of the methodology that Kentucky-American used to develop its proposed ROE. First, he argues that Dr. Vander Weide has made an inappropriate adjustment to the spot dividend yield. Second, he asserts that the Kentucky-American study relies exclusively on the

---

[185] *Id.* at 27. I/B/E/S is a division of Thomson Reuters that reports analysts' earnings per share ("EPS") growth forecasts for a broad group of companies. The I/B/E/S growth rates are widely circulated in the financial community, include the projections of reputable financial analysts who develop estimates of future EPS growth, are reported on a timely basis to investors, and are widely used by institutional and other investors.

[186] *Id.* at 27.

[187] *Id.* at 3.

forecasted growth rates of Wall Street analysts and *Value Line* to compute the equity cost rate, that the long-term earnings growth rates of Wall Street analysts are overly optimistic and upwardly-biased, and that the estimated long-term EPS growth rates of *Value Line* are overstated. Third, Dr. Woolridge contends that the risk premium and CAPM approaches require an estimate of the base interest rate and the equity risk premium. In both approaches, he asserts, Dr. Vander Weide's base interest rate is above current market rates.[188]

Dr. Woolridge also takes strong exception to Dr. Vander Weide's position in measuring the equity risk premium, as well as the magnitude of equity risk premium. He contends that Dr. Vander Weide has used excessive equity risk premiums that do not reflect current market fundamentals. Dr. Vander Weide uses a historical equity risk premium which is based on historic stock and bond returns and calculates an expected risk premium in which he applies the DCF approach to the S&P 500 and public utility stock. Risk premiums based on historic stock and bond returns, Dr. Woolridge asserts, are subject to empirical errors which result in upwardly biased measures of expected equity risk premiums. Dr. Woolridge further asserts that Dr. Vander Weide's projected equity risk premiums, which use analysts' EPS growth rate projections, include unrealistic assumptions regarding future economic and earnings growth and stock returns.[189]

Contending that the utility has failed to identify any actual flotation costs and questioning whether the necessary conditions that support the use of a flotation cost

[188] Direct Testimony of J. Randall Woodridge at 3-4.

[189] *Id.* at 73-75.

adjustment are present in the current case, Dr. Woolridge challenges the appropriateness of Dr. Vander Weide's use of flotation cost adjustment in his DCF analysis.[190]

Finally, Dr. Woolridge takes issue with Kentucky-American's proxy group. He notes that Dr. Vander Weide's proxy group of water companies includes a water company with less than two years of dividend payments and another which has agreed to be sold to an investor group.[191] Six of the twelve members of the gas proxy group, he further notes, have a low percentage of revenues derived from the regulated gas distribution business or are engaged in riskier business ventures. As Dr. Vander Weide's gas proxy group has a number of companies with significant non-regulated gas activities and is riskier than regulated water and gas companies, the AG argues, the results for that group should be ignored.[192]

Dr. Woolridge conducted his own analysis, applying the DCF model and the CAPM methods to a water proxy group and a gas proxy group and affording primary weight to the results of the DCF analysis. Based upon that analysis, he proposes an ROE range from 7.3 percent to 9.3 percent and recommends an awarded ROE of 9.25.[193]

To perform his analysis, Dr. Woolridge uses a proxy group of nine publicly-held water utility companies covered by *AUS Utility Reports* and a second proxy group of

---

[190] *Id.* at 71-73.

[191] *Id.* at 53.

[192] *Id.* at 53-54.

[193] *Id.* at 2.

nine natural gas distribution companies covered by the Standard Edition of *Value Line*. The water proxy group received 92 percent of its revenues from regulated water operations and had a common equity ratio of 49.0 percent. The gas proxy group received 63 percent of revenues from regulated gas operations and had a common equity ratio of 52 percent.[194]

Dr. Woolridge argues that the use of natural gas distribution companies as a proxy for Kentucky-American is appropriate since the financial data necessary to perform a DCF analysis on the members of the water proxy group, as well as analysts' coverage of water utilities, is limited. He also argues that the return requirements of gas companies and water companies should be similar as both industries are capital intensive, heavily regulated, and provide essential services with rates set by state regulatory commissions.[195]

Dr. Woolridge places significant emphasis on current economic conditions and concluded that short- and long-term credit markets have "loosened" considerably and that the stock market has rebounded significantly from 2009's lows.[196] He further states that the investment risk of utilities is currently very low and that the cost of equity for utilities is among the lowest of all industries in the U.S. as measured by their betas.[197]

LFUCG witness Baudino also takes exception to several aspects of Kentucky-American's ROE analyses. First, he notes the presence of highly diversified gas

---

[194] *Id.* at 11-12.

[195] *Id.* at 10-11.

[196] *Id.* at 10.

[197] *Id.* at 20-21.

companies in Kentucky-American's gas proxy group whose businesses are more diverse, unregulated and tend to have great risk. As such, he argues, they are "poor proxies for . . . [Kentucky-American's] low-risk water distribution operation" and tend to inflate Kentucky-American's DCF analysis.[198]

Mr. Baudino contends that Dr. Vander Weide erred by failing to include forecasted dividend growth in his DCF analyses. With respect to regulated utility companies, he argues, dividend growth provides the primary source of cash flow to the investor. While earnings growth fuels dividend growth, *Value Line*'s dividend growth forecasts are widely available to investors and can reasonably be assumed to influence their expectations with respect to growth. *Value Line*'s dividend growth forecasts, Mr. Baudino states, suggest that near-term dividend growth will be less than forecasted earnings growth. Dr. Vander Weide's failure to include this information, Mr. Baudino concludes, led to a significant overstatement of all of his DCF results.[199]

Mr. Baudino further contends that Dr. Vander Weide's use of a quarterly DCF model is unnecessary and overcompensates investors. This model, he argues, compensates investors twice for the reinvestment effect associated with the quarterly payment of dividend. Moreover, he states, quarterly compounding is likely already accounted for in a company's stock price since investors know that dividends are paid quarterly and that they may reinvest those cash flows.[200]

---

[198] Direct Testimony of Richard A. Baudino at 15.

[199] *Id.* at 33, 37-38.

[200] *Id.* at 38-39.

Mr. Baudino also argues that the use of a flotation adjustment is unnecessary. To the extent that investors even account for such costs, he states, current stock prices already account for flotation costs. The adjustment, he states, essentially assumes that the current stock price is wrong and must be adjusted downward to increase the dividend yield and the resulting cost of equity.[201]

Mr. Baudino also alleges several problems with Dr. Vander Weide's risk premium approach. He argues that Dr. Vander Weide's assumption that investors require an unchanging risk premium based on historic returns of stocks over bonds fails to take into account that changing economic conditions will affect investors' risk premium requirements. Under current economic conditions, Mr. Baudino asserts, investors' requirements may differ significantly from a long-term historical risk premium.[202]

Mr. Baudino next argues that Dr. Vander Weide failed to adjust his historical risk premium, which uses the S&P 500 stock portfolio, for the risk premium expectations for utility companies. Investor-expected risk premiums for water utility stocks over bonds, Mr. Baudino states, are likely much lower than the expected risk premium for unregulated companies in the S&P 500. Using the S&P 500 risk premium, Mr. Baudino argues, overstates the risk premium ROE for a low-risk water company such as Kentucky-American.[203]

Mr. Baudino also contends that Dr. Vander Weide's use of S&P utilities to calculate the expected risk premium ROE for Kentucky-American is inappropriate. Low-

---

[201] *Id.* at 39-40.

[202] *Id.* at 41.

[203] *Id.* at 41-42.

risk water companies, he contends, are likely to have a lower expected ROE than the S&P Utilities and thus a risk premium using the S&P Utilities will overstate the risk premium ROE for regulated water companies.

Mr. Baudino also disputes Dr. Vander Weide's decision to disregard his CAPM results because CAPM underestimates required returns for securities with betas of less than one. Mr. Baudino argues that there is little evidence that the CAPM bias has any applicability to regulated utilities. Regulated water utilities, he asserts, have low betas because they are low in risk.[204]

Mr. Baudino performed several DCF analyses for two comparison groups of utilities, one composed of regulated water utilities and one composed of regulated natural gas distribution utilities.[205] He also performed two CAPM analyses. Based upon the results of these analyses, he recommended a ROE range from 9.0 percent to 10.0 percent and a ROE of 9.50 percent.[206]

In his rebuttal testimony, Dr. Vander Weide addresses the criticism of his analysis and critiques the analyses of Intervenor witnesses. Countering criticism of his proxy group selections, he notes that his proxy group of natural gas utilities has a higher *Value Line* safety rating and higher average bond rating than AWWC and his proxy group of water utilities has a higher S&P bond rating than AWWC and the same *Value Line* safety ranking.[207]

---

[204] *Id.* at 42-43.

[205] *Id.* at 13-16.

[206] *Id.* at 31.

[207] Rebuttal Testimony of James Vander Weide at 5.

As to his use of EPS growth rates in his DCF analysis, Dr. Vander Weide argues that differences in EPS growth rates and historical growth rates for water utilities do not reduce the reliability of his analysis. He contends that differences in historical and projected growth rates for the water utilities indicate that water utilities are likely to grow more rapidly in the future than they have in the past. His DCF model, he asserts, is intended to capture investors' expectations about the future. Moreover, he argues, historical growth rates are inherently inferior to analysts' forecasts because analysts' forecasts already incorporate all relevant information regarding historical growth rates and also incorporate the analysts' knowledge about current conditions and expectations regarding the future. He refers to several studies that "demonstrate that stock prices are more highly correlated with analysts' growth rates than with either historical growth rates or the internal growth rates."[208]

Dr. Vander Weide rejected criticism of his use of a quarterly DCF model. He testified that all of the companies within his proxy groups paid quarterly dividends and noted that the same applied for those companies in Dr. Woolridge's proxy group. He further testified that, as the DCF model is based on the assumption that a company's stock price is equal to the expected future dividends associated with investing in the company's stock, an annual DCF model cannot be based upon this assumption when dividends are paid quarterly.[209]

Dr. Vander Weide takes exception to Dr. Woolridge's internal growth method. He argues that this method underestimates the expected growth of his proxy companies

---

[208] *Id.* at 13-25.

[209] *Id.* at 62.

by neglecting the possibility that such companies can grow by issuing new equity at prices above book value. He notes that many of the proxy companies are currently engaging in this practice or are expected to do so in the future. This possibility is noteworthy, he asserts, because the water industry is expected to undertake substantial infrastructure investments in the near future and to finance those investments in part through this practice.[210]

Dr. Vander Weide also expresses concerns about aspects of Mr. Baudino's analysis. He contends that the use of DPS growth forecasts to estimate the growth component of Baudino's DCF model understates long-run future growth and that such forecasts are less accurate indicators of long-run future growth than earnings growth forecasts.[211]

Based upon our review of the record, we find that Kentucky-American's proposed ROE should be denied. We find Kentucky-American's use of natural gas distribution companies as proxies for water utilities to be inappropriate. While natural gas distribution companies and water utilities have similar types of fixed investments, the nature of the risks that each industry faces is sufficiently different to prevent the use of natural gas companies as a proxy. While both industries deliver a commodity through underground pipes, several of the companies within the natural gas proxy group that Kentucky-American has used engage in exploration, production, transmission, and other non-regulated and non-distribution activities. These activities extend well beyond a distribution function and have greater risk.

---

[210] *Id.* at 12.

[211] *Id.* at 55-59.

We find that an ROE of 9.7 percent provides Kentucky-American with a fair and reasonable rate of return. In reaching our finding, we have focused upon the water utilities within the proposed proxy group. This group consists of large and small publicly traded water utilities. While Kentucky-American is a relatively small water utility, it is part of a large, multi-state operation that has access to investment capital under conditions that few small water utilities could obtain. Accordingly, we are of the opinion that this group is a more accurate indicator of risk and market expectations.

This finding also reflects Kentucky-American's recent regulatory history. Kentucky-American's frequency of rate case applications since 1992 clearly demonstrates management's focused efforts to minimize regulatory risk and the risk associated with the recovery of capital investments. Kentucky-American has applied for rate adjustments on a more frequent basis than other water utilities within the proxy group. Furthermore, Kentucky-American has used a forecasted test period with each rate application–a mechanism that also tends to reduce the risk associated with the recovery of capital investments.

In reaching our finding, we have also excluded any flotation cost adjustment from our analysis and have placed much greater emphasis on the DCF and the CAPM model results of the water utility proxy groups. While recognizing the value of historic data for use in obtaining estimates, we have also considered analysts' projections regarding future growth. Finally, in assessing market expectations, we have given considerable weight to present economic conditions.

Weighted Cost of Capital. Applying the rates of 6.38 percent for long-term debt, 7.75 percent for preferred stock, 1.90 percent for short-term debt, and 9.70 percent for common equity to the adjusted capital structure produces an overall cost of capital of 7.74 percent. We find this cost to be reasonable.

Authorized Increase

The Commission finds that Kentucky-American's net operating income for rate-making purposes is $28,116,014. We further find that this level of net operating income requires an increase in forecasted present rate revenues of $18,825,137.[212]

Cost-of-Service Study

Kentucky-American included with its application a cost-of-service allocation study[213] that is based upon the base-extra capacity method. This methodology is widely recognized within the water industry as an acceptable methodology for allocating costs.[214] This Commission has also accepted the use of this methodology for cost allocation and development of water service rates. No party has objected to the findings of the cost-of-service study. We accept the study's findings.

General Water Rates

The rates and charges contained in the Appendix to this Order are based on findings contained in the cost-of-service study, as adjusted by our findings regarding the

---

[212]

Net Investment Rate Base	$ 363,255,997
Multiplied by: Rate of Return	x 7.7400%
Operating Income Requirement	$ 28,116,014
Less: Forecasted Net Operating Income	- 16,717,697
Operating Income Deficiency	$ 11,398,317
Multiplied by: Revenue Conversion Factor	x 1.651571600
Increase in Revenue Requirement	$ 18,825,137

[213] Application, Exhibit 36.

[214] American Water Works Association, *Principles of Water Rates, Fees and Charges* 50 (5th Ed. 2000).

reasonableness of the costs in the proposed test period. Those rates and charges will produce the required revenue requirement based upon the forecasted sales. For a residential customer who uses an average of 5,000 gallons per month, these rates will increase his or her monthly bill from $27.46 to $35.40, or approximately 28.9 percent.

Service to Low-Income Customers

The Commission recognizes that a significant portion of Kentucky-American's customers have annual incomes that are at or below the Federal Poverty Guideline.[215] We further recognize that the approved rate adjustment will more adversely affect these customers than those with higher annual incomes. CAC has presented several proposals to provide some relief to the customers. Having carefully considered each of these proposals, we find that each should be implemented or given further study and consideration.

CAC has proposed that Kentucky-American be required to maintain more complete records regarding customer payment and termination of service for non-payment in a manner that permits systematic analysis. It notes that Kentucky-American presently cannot ascertain the number of customers who make late payments, a customer's frequency of late payments, the number of terminations for late payments, or

---

[215] In 2008, approximately 15.4 percent of Fayette County residents were living at or below the Federal Poverty Guideline. Of the remaining eight counties in which Kentucky-American provides water service, the percentage of persons living at or below the poverty line in 2008 ranged from 9.7 percent to 17.0 percent. It is estimated that 15.4 percent of Fayette County residents were at or below the Federal Poverty Guideline in 2008. Of the remaining eight counties in which Kentucky-American has operations, the percentage of individuals at or below the poverty line ranged from 9.7 percent to 17.0 percent. *See* U.S. Census Bureau Small Area Income and Poverty Estimates, *available at* http://www.census.gov/did/www/saipe/data/index.html (last visited Nov. 2, 2010).

the specific service (e.g., water, sewer, water quality) for which non-payment has occurred and serves as the basis for termination.[216] CAC witness Burch testified this information would provide a better means of assessing the affordability of Kentucky-American's rates and developing policies to assist low income customers.[217] Kentucky-American confirms that its present records system will not allow quick and cost-effective analysis on these subjects.[218]

If the Commission is to properly review and assess the affordability of Kentucky-American's rates, we must have accurate and reliable information regarding customer payment. Given the limitations of Kentucky-American's record systems, that information is presently unavailable. Accordingly, we find that Kentucky-American should develop and implement as soon as possible a plan to accurately record and determine the number of customers making payments after the due date, the frequency of late payments by each customer, the number of service terminations for nonpayment for each customer account and company-wide, and the specific services that were not paid when water service is terminated for non-payment.

CAC urges the Commission to restructure Kentucky-American's proposed rate design to create a graduated, tiered rate structure. It asserts that an inclining block structure that provides for a minimum quantity of water at an inexpensive level and increasing rates based upon increased usage would benefit all customers. Such a rate

---

[216] CAC's Brief at 6-7.

[217] VR: 8/11/10; 15:41:45-15:43:20.

[218] Kentucky-American's Response to CAC's Second Request for Information, Item 1.

structure, CAC argues, would make a minimum quantity of water affordable to low-income customers and would promote conservation. As an alternative to immediately implementing such rate design, CAC requests that Kentucky-American be directed to "work with the Attorney General, low income advocates, and other interested parties to design a rate system on this concept."[219] It further proposes that the Commission establish a collaborative effort that includes all interested parties and Commission Staff to address affordability issues. All other parties appear in agreement with the proposal to create a working group to study rate design issues.

We find insufficient evidence in the record to support CAC's rate design proposal or to clearly demonstrate that the implementation of such proposal will benefit low-income customers or create appropriate pricing signals. Accordingly, we have not incorporated CAC's rate design proposal into Kentucky-American's rates. We find, however, that CAC's proposal should be further studied and additional customer data gathered to permit a thorough assessment of the proposal's potential effects.

Recognizing that the affordability of water service is a complex and multi-faceted subject that must be approached on several levels, the Commission finds considerable merit to CAC's proposal to undertake a collaborative effort to study this subject. Such an effort, however, should not be limited to examining potential rate design options to enhance the affordability of water service, but should consider all potential regulatory and legislative solutions to this perplexing issue. We find that Kentucky-American should initiate this collaborative effort by arranging, within 60 days of the date of this Order, a meeting of all interested parties to discuss and study potential regulatory and

---

[219] CAC's Brief at 8.

legislative solutions to the increasing lack of affordability of water service for low income customers. Moreover, Kentucky-American should file with the Commission periodic written reports on the status of these meetings and submit a final written report on the collaborative group's efforts no later than November 1, 2011. We direct Commission Staff to assist the collaborative group's efforts to the fullest extent that its limited resources permit and encourage all interested parties, including those groups that did not intervene in this proceeding, to actively participate.

Other Issues

Tap-On Fees. Kentucky-American proposes to increase its tap-on fees from 13 percent to 22 percent to reflect the five-year average cost of a service connection. Kentucky-American's tap fees are currently based upon an average of actual costs of connections from 2005 to 2007. Kentucky-American witness Bridwell testified that significant increases in connection costs have occurred since that time. Raw material costs increased dramatically in 2008 and have not yet returned to pre-2008 levels. Additionally, the number of new service connections significantly decreased in 2008 and 2009 due to a reduction in economic activity. As a result, there were fewer installations over which to spread the fixed costs related to such installations.[220]

Kentucky-American has historically used a three-year average of connection costs to establish its tap-on fees. In the present case, it proposes to base these fees on a five-year average to reduce the effect of increasing costs and current economic conditions. The Commission acknowledges and supports Kentucky-American in its

[220] Direct Testimony of Linda C. Bridwell at 2-3.

efforts to lessen the increase in tap-on fees for its customers and accepts the change in the calculation of the average costs over a five-year period.

Based upon our review of the record, we find that the proposed revisions to tap-on fees will not result in fees that exceed the cost of the service connection, are reasonable, comply with 807 KAR 5:011, Section 10, and should be approved.

Reduced Rate/Free Service for Public Fire Hydrants.[221] Kentucky-American currently provides water service to approximately 7,388 public fire hydrants.[222] LFUCG owns approximately 6,811 of these hydrants.[223] Approximately 6,920 of these hydrants are located in Fayette County. Under the terms of Kentucky-American's present rate schedules, governmental bodies pay a monthly or annual charge for each hydrant.

LFUCG argues that a reasonable portion of the public fire hydrant costs should be assigned to other customer classes to reflect the benefits that other users of the water distribution system receive from the existence of public fire protection service (for example, lower insurance rates and enhanced public safety) and the existence of hydrants (for example, improved water quality due to greater line-flushing capability). It

[221] Under the terms of Kentucky-American's tariff, a public fire hydrant is a fire hydrant contracted for or ordered by Urban County, County, State or Federal Governmental agencies or institutions and connected to a municipal or private fire connection used solely for fire protection purposes. Tariff of Kentucky-American Water Company, P.S.C. Ky. No. 6, Twenty-Third Revised Sheet No. 53.

[222] Kentucky-American's Response to LFUCG's First Request for Information, Item 9.

[223] *Id.*

requests that the Commission order or otherwise encourage Kentucky-American to develop a free or reduced public fire hydrant rate for use in a future rate proceeding.[224]

While KRS 278.170(3) permits a utility to provide free or reduced-rate service for fire protection purposes, LFUCG's proposal raises a number of difficult policy issues. Free or reduced-rate fire hydrant service effectively shifts the fire protection service costs from governmental bodies to other users and thus requires a corresponding increase in the rates for general water service customers. Because Kentucky-American has a unified tariff and serves areas outside of Fayette County for which no fire protection service is provided, the potential exists that Kentucky-American customers who reside outside of Fayette County will be subsidizing through their rates fire protection services for Fayette County residents.[225]

LFUCG's proposal will produce an income transfer from Kentucky-American customers to local, state, and federal government entities. The public, which includes Kentucky-American ratepayers, currently pays indirectly for public fire hydrant service through local, state and federal taxes. Government agencies use collected tax revenues to pay Kentucky-American directly for public fire hydrant service. Allocating the costs of providing public fire hydrant service to general service customers will reduce or eliminate the charges that government entities must pay and effectively provide those agencies with additional funds for other uses. It will also require general

---

[224] LFUCG's Brief at 8.

[225] To the extent that public fire hydrant service benefits non-customers who own property in Kentucky-American's service area, the effect of allocating the costs of public fire hydrant service to general service customers is to provide a subsidy to those non-customers.

service customers to pay higher rates for water service. Unless a reduction occurs in these customers' taxes to offset the increased amount for water service, these customers will be paying a larger portion of their income for the same level of services.

Allocating public fire hydrant service costs to general service rates also increases the likelihood that pricing signals will be distorted and public accountability will be lessened. Under the current pricing scheme, the cost of public fire hydrant service is clearly known to the public. Kentucky-American bills the governmental entity for that service. The governmental entity must allocate and pay those bills from its available funds. Its records and budgeting process are subject to public review and inspection. The decisions regarding the availability of public fire hydrant service and amount of public funds (and assessed private funds) to be devoted to such service are made in full public view and with the opportunity for public comment. Allocating public fire hydrant service costs to general service users effectively hides these costs from public view and discussion and renders informed public decisions on the availability and appropriateness of such service more difficult.

In light of these concerns and as LFUCG will be the primary beneficiary of any free or reduced public fire hydrant rate, the Commission finds that LFUCG, not Kentucky-American, is the most appropriate party to develop a proposal for such rate. We respectfully decline LFUCG's request to order or otherwise encourage Kentucky-American to develop a free or reduced public fire hydrant rate for future use without adequate evidence. By this Order, however, we direct that Kentucky-American make its records available to LFUCG and respond to all reasonable inquires from LFUCG regarding public fire hydrant service to enable LFUCG to develop its own proposal.

Should Kentucky-American fail to comply with this directive, LFUCG should inform the Commission of this failure and request our assistance in obtaining the required information.

Tariff Revisions Related to Fire Protection Mains. Kentucky-American currently does not meter water usage provided through fire service connections. Despite restrictions in Kentucky-American's tariff that require that water from these connections be used solely for fire protection purposes,[226] Kentucky-American employees have observed water withdrawals from some fire service connections for other purposes.[227] As a result, Kentucky-American proposes revisions to its present tariff to permit the installation of meters on fire service connections and the assessment of usage charge on all non-fire related flows when a reasonable belief exists that water is being used for non-fire protection purposes.

The Commission finds that the proposed revisions are reasonable and should be approved. They are consistent with the findings and recommendations of a recently completed report on Kentucky-American's non-revenue water.[228] Enforcement of Kentucky-American's proposed tariff language will likely reduce the level of non-revenue water by permitting Kentucky-American to track and charge usage on these previously unmetered service connections. It will also provide a means through which Kentucky-American can enforce its prohibition against non-fire protection usage on such connections.

---

[226] Kentucky-American Water Company Tariff No. 6, Sheet 10 (Feb. 17, 1983).

[227] Direct Testimony of Linda C. Bridwell at 7.

[228] Gannett Fleming, Analysis of Non-Revenue Water, Task 5 (Sep. 2009).

Demand Management Plan. In its brief, LFUCG requests that the Commission order Kentucky-American to develop a new demand management plan. In support of its request, it notes that Kentucky-American's existing plan was developed in 2001 and that significant changes to Kentucky-American's operations have occurred since then. It further asserts that a new plan is essential to determining whether Kentucky-American has sufficient water to provide wholesale service to other water utilities within the central Kentucky area and the direction of Kentucky-American's planning. The Commission agrees and by this Order directs Kentucky-American to file such plan no later than the filing of its next application for general rate adjustment.

Termination of Water Service for Debts Owed to LFUCG. Pursuant to an agreement with LFUCG, Kentucky-American bills and collects from its Fayette County customers LFUCG Water Quality Management Fee, LFUCG Landfill Charges, and LFUCG Sewer charges. This agreement provides that monies received from its customers will be applied to unpaid charges in the following priority: (1) water service charges; (2) LFUCG Water Quality Charges, (3) LFUCG Landfill Charges, and (4) LFUCG Sewer charges.[229] The agreement provides that water service will be terminated for failure to pay LFUCG sewer charges. Given the agreement's priority provisions which effectively allocate a customer's payment of LFUCG sewer charges to LFUCG Water Quality Charges and Landfill Charges, Kentucky-American has agreed to terminate a customer's water service for a customer's failure to pay LFUCG Water Quality Charges or LFUCG Landfill Charges.[230]

---

[229] Kentucky-American's Response to Hearing Data Request, Item 13.

[230] *Id.*, Item 14.

In Case No. 95-238,[231] Kentucky-American applied for approval of its initial agreement with LFUCG and for a deviation from 807 KAR 5:006, Section 14, to permit the discontinuance of water service to any customer who failed to pay sanitary sewer charges owed to LFUCG. While noting that that 807 KAR 5:006, Section 14, "permits a utility to discontinue service only for nonpayment of charges for services which it provides," we found that KRS Chapter 96 expressly authorized such agreements[232] and required a water supplier to discontinue water service to premises for a customer's failure to pay sewer service charges when the governing body of the municipal sewer facilities identifies the delinquent customer and notifies the water supplier to discontinue service.[233] We further found that, as the provisions of KRS Chapter 96 and 807 KAR 5:006, Section 14, were in conflict and that KRS Chapter 96 was more specific, those provisions controlled.[234] Hence, we reasoned, no deviation from 807 KAR 5:006, Section 14, was required and no Commission approval of the Agreement between Kentucky-American and LFUCG was required.

[231] Case No. 95-238, An Agreement Between Lexington-Fayette Urban County Government and Kentucky-American Water Company for the Billing, Accounting and Collection of Sanitary Sewer Charges, at 3 (Ky. PSC June 30, 1995). The agreement addressed only billing and collection of sanitary sewer charges and did not address either water quality fees or landfill fees.

[232] *See* KRS 96.940.

[233] *See* KRS 96.934.

[234] Case No. 95-238, Order of June 30, 1995, at 3-4. The conflict existed between provisions of KRS Chapter 96 and KRS 278.280(2), which provides the Commission "shall prescribe rules for the performance of any service or the furnishing of any commodity of the character furnished or supplied by" a utility.

Kentucky-American's present practice of discontinuing service for failure to pay landfill fees and water quality management fees, however, has no statutory basis. KRS Chapter 96 requires a water supplier to discontinue water service only to a premise that fails to pay municipal sanitary sewer charges. It makes no reference to landfill fees or water quality or storm drainage charges. Consequently, there is no conflict between KRS Chapter 96 and 807 KAR 5:006, Section 14, nor are there any restrictions on that regulation's application to the water utility's practice of discontinuing water service for failure to pay a landfill fee or water quality management fee.

As a general rule, a public utility "cannot refuse to render the service which it is authorized to furnish, because of some collateral matter not related to that service."[235] The purpose of the water quality management fee is to fund LFUCG's storm water management program and surface water runoff facilities.[236] The fee is based upon the size and the condition of a real estate tract. Similarly, LFUCG's landfill fee is intended to fund "the operational and capital costs of solid waste disposal" and is based on the

[235] Maurice T. Brunner, Annotation, *Right of Municipality to Refuse Services Provided By It to Resident for Failure of Resident to Pay for Other Unrelated Services*, 60 A.L.R. 3d 760 (1974). *See also* 64 Am. Jur. 2d *Public Utilities* § 23 (2010); OAG 79-417 (July 17, 1979). *But see Cassidy v. City of Bowling Green, Ky.*, 368 S.W.2d 318 (Ky. 1963).

[236] LFUCG Ordinance No. 73-2009.

number and type of waste disposal containers.[237] We can find no relationship between storm water management or garbage collection and water service.[238]

Absent express statutory authorization or a deviation from 807 KAR 5:006, Section 14, Kentucky-American may not terminate water service because of a customer's failure to pay charges related to storm water service or garbage service. Kentucky-American, however, has effectively engaged in this practice by applying any amounts billed and collected for LFUCG to landfill disposal and water quality management fees before sanitary sewer charges. The Commission finds that Kentucky-American should cease this practice immediately and should instead apply any monies collected for LFUCG first to LFUCG sanitary sewer charges and then to landfill disposal and water quality management fees.[239]

SUMMARY

After consideration of the evidence of record and being otherwise sufficiently advised, the Commission finds that:

1. Kentucky-American's proposed rates would produce revenues in excess of those found reasonable herein and should be denied.

---

[237] LFUCG Code, Section 16-16.

[238] In contrast, Kentucky courts have found the use of water service and sanitary sewer service to be "interdependent." *See, e.g., Rash v. Louisville and Jefferson County Metropolitan Sewer Dist.*, 217 S.W.2d 232, 239 (Ky. 1949).

[239] 807 KAR 5:006, Section 27, authorizes deviations from the Commission's General Rules for good cause. Kentucky-American may apply to the Commission for a deviation from 807 KAR 5:006, Section 14, to continue its current practice. Our action should not be construed as expressing a position on the merits of such application.

2. Kentucky-American's proposed tap-on fees are reasonable and should be approved.

3. Kentucky-American's proposed rules related to fire protection mains are reasonable and should be approved.

4. The rates in the Appendix to this Order are fair, just, and reasonable and should be charged by Kentucky-American for service rendered on and after September 28, 2010.

5. Kentucky-American should, within 60 days of the date of this Order, refund to its customers with interest all amounts collected from September 28, 2010 through the date of this Order that are in excess of the rates that are set forth in the Appendix to this Order. Interest should be based upon the average of the Three-Month Commercial Paper Rate as reported in the Federal Reserve Bulletin and the Federal Reserve Statistical Release on the date of this Order.

IT IS THEREFORE ORDERED that:

1. Kentucky-American's proposed rates are denied.

2. The rates set forth in the Appendix to this Order are approved for service rendered on and after September 28, 2010.

3. Within 60 days of the date of this Order, Kentucky-American shall refund to its customers with interest all amounts collected for service rendered from September 28, 2010 through the date of this Order that are in excess of the rates set forth in the Appendix to this Order.

4. Kentucky-American shall pay interest on the refunded amounts at the average of the Three-Month Commercial Paper Rate as reported in the Federal

Reserve Bulletin and the Federal Reserve Statistical Release on the date of this Order. Refunds shall be based on each customer's usage while the proposed rates were in effect and shall be made as a one-time credit to the bills of current customers and by check to customers that have discontinued service since September 28, 2010.

5. Within 75 days of the date of this Order, Kentucky-American shall submit a written report to the Commission in which it describes its efforts to refund all monies collected in excess of the rates that are set forth in the Appendix to this Order.

6. Within 20 days of the date of this Order, Kentucky-American shall file its revised tariff sheets containing the rates approved herein and signed by an officer of the utility authorized to issue tariffs.

7. Kentucky-American's proposed revisions to Tariff Sheets No. 52, No. 53, and No. 53.1 are approved.

8. LFUCG's request that Kentucky-American develop a free or reduced public fire hydrant rate for use in a future rate proceeding is denied.

9. Kentucky-American shall make all records related to fire protection service and public fire hydrant service available for LFUCG's inspection and review and shall respond to all reasonable inquiries from LFUCG regarding public fire hydrant service within a reasonable time.

10. Within 60 days of the date of this Order, Kentucky-American shall develop and file with the Commission a plan to accurately record and determine the number of customers making payments after the due date, the frequency of late payments by each customer, the number of service terminations for non-payment for each customer account and company-wide, and the specific service(s) that are not paid when water

service is terminated for non-payment. This plan shall further identify the cost of implementing such plan and the time necessary for implementation.

11. Unless the Commission otherwise directs, Kentucky-American shall implement the plan submitted in accordance with ordering paragraph 10 within 120 days of the date of this Order.

12. No later than the filing of its next application for general rate adjustment Kentucky-American shall file a revised demand management plan with the Commission.

13. a. Within 60 days of the date of this Order, Kentucky-American shall initiate the collaborative effort described in this Order by convening a meeting of all interested parties, to include all parties of record in this case, to identify and study potential regulatory and legislative solutions to enhance and improve the affordability of water service for low-income customers.

b. No later than January 31, 2011, and every month thereafter, Kentucky-American shall file with the Commission a written report on the efforts of the collaborative group to develop potential regulatory and legislative solutions to enhance and improve the affordability of water service for low-income customers.

c. No later than November 1, 2011, Kentucky-American shall file with the Commission a final written report on the collaborative group's efforts.

14. Until granted a deviation from 807 KAR 5:006, Section 14, authorizing such practice, Kentucky-American shall refrain from its practice of applying monies collected from a customer for LFUCG to landfill disposal and water quality management fees before applying those monies to LFUCG sanitary sewer charges and from terminating water service to a customer who has failed to pay fully all LFUCG fees and

charges where the amount paid is equal to or exceeds all outstanding charges for LFUCG sanitary sewer service.

15. Any documents filed with the Commission pursuant to ordering paragraphs 5, 6, 10, 12, and 13 shall reference this case number and shall be retained in the utility's general correspondence file.

By the Commission

ENTERED
DEC 14 2010
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2010-00036 DATED DEC 1 4 2010

The following rates and charges are prescribed for the customers in the area served by Kentucky American Water Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of the Commission prior to the effective date of this Order.

Meter Charge Rates

Meter Size	
5/8-Inch	$8.90
3/4-Inch	13.35
1-Inch	22.25
1 1/2-Inch	44.50
2-Inch	71.20
3-Inch	133.50
4-Inch	222.50
6-Inch	445.00
8-Inch	712.00

Consumption Rates

Customer Category	Rate Per 100 Cubic Feet All Consumption	Rate Per 1,000 Gallons All Consumption
Residential	$3.97530	$5.30040
Commercial	3.62100	4.82800
Industrial	2.92100	3.89467
Municipal & Other Public Authority	3.18390	4.24520
Sales for Resale	3.15700	4.20933

Municipal or Private Fire Protection Service

Size of Service	Rate Per Month	Rate Per Annum
2-Inch	$ 8.11	$ 97.29
4-Inch	32.63	391.56
6-Inch	73.40	880.76
8-Inch	130.49	1,565.88
10-Inch	203.94	2,447.31
12-Inch	293.75	3,525.05
14-Inch	399.89	4,798.70
16-Inch	522.19	6,266.32

Rates for Public or Private Fire Service

Rates for Public Fire Service	Rate Per Month	Rate Per Annum
For each public fire hydrant contracted for or ordered by Urban County, County, State or Federal Governmental Agencies or Institutions	$37.84	$454.03
Rates for Private Fire Service		
For each private fire hydrant contracted for by Industries or Private Institutions	$72.52	$871.22

Tapping (Connection) Fees

Size of Meter Connection	
5/8-Inch	$817.00
1-Inch	1,569.00
2-Inch	3,536.00
Service larger than 2-Inch	Actual Cost

Honorable David Jeffrey Barberie
Corporate Counsel
Lexington-Fayette Urban County Government
Department Of Law
200 East Main Street
Lexington, KY 40507

Honorable David Edward Spenard
Assistant Attorney General
Office of the Attorney General Utility & Rate
1024 Capital Center Drive
Suite 200
Frankfort, KY 40601-8204

Honorable Leslye M Bowman
Director of Litigation
Lexington-Fayette Urban County Government
Department Of Law
200 East Main Street
Lexington, KY 40507

A.W. Turner
Kentucky-American Water Company aka Kentucky
2300 Richmond Road
Lexington, KY 40502

Honorable Dennis G Howard II
Assistant Attorney General
Office of the Attorney General Utility & Rate
1024 Capital Center Drive
Suite 200
Frankfort, KY 40601-8204

Honorable Lindsey W Ingram, III
Attorney at Law
STOLL KEENON OGDEN PLLC
300 West Vine Street
Suite 2100
Lexington, KY 40507-1801

Heather Kash
Office of the Attorney General Utility & Rate
1024 Capital Center Drive
Suite 200
Frankfort, KY 40601-8204

Louise Magee
Kentucky-American Water Company aka Kentucky
2300 Richmond Road
Lexington, KY 40502

Iris G Skidmore
415 W. Main Street, Suite 2
Frankfort, KY 40601

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.	DOCKET NO. 170006-WS ORDER NO. PSC-17-0249-PAA-WS ISSUED: June 26, 2017

The following Commissioners participated in the disposition of this matter:

JULIE I. BROWN, Chairman
ART GRAHAM
RONALD A. BRISÉ
JIMMY PATRONIS
DONALD J. POLMANN

NOTICE OF PROPOSED AGENCY ACTION
ORDER ESTABLISHING AUTHORIZED RANGE OF RETURNS ON COMMON EQUITY FOR WATER AND WASTEWATER UTILITIES

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission (Commission or FPSC) that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code (F.A.C.).

Background

Section 367.081(4)(f), Florida Statutes (F.S.), authorizes this Commission to establish, not less than once each year, a leverage formula to calculate a reasonable range of returns on equity (ROE) for water and wastewater (WAW) utilities. The leverage formula methodology currently in use was established in Order No. PSC-01-2514-FOF-WS.[1] On October 23, 2008, this Commission held a formal hearing in Docket No. 080006-WS to allow interested parties to provide testimony regarding the validity of the leverage formula.[2] Based on the record in that proceeding, this Commission approved the 2008 leverage formula in Order No. PSC-08-0846-

[1]Order No. PSC-01-2514-FOF-WS, issued December 24, 2001, in Docket No. 010006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity of water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.
[2]At the May 20, 2008, Commission Conference, upon request of the Office of Public Counsel, this Commission voted to set the establishment of the appropriate leverage formula directly for hearing.

FOF-WS.[3] In that order, this Commission reaffirmed the methodology that was previously approved in Order No. PSC-01-2514-FOF-WS.

This order continues to use the leverage formula methodology established in Order No. PSC-01-2514-FOF-WS and reaffirmed in Order No. PSC-08-0846-FOF-WS. This methodology uses ROEs derived from financial models applied to an index of natural gas utilities, as this Commission determined that there were an insufficient number of utilities that meet the requisite criteria to assemble an appropriate proxy group using only WAW utilities. Therefore, since 2001, we have used natural gas utilities as the proxy companies for the leverage formula. There are approximately 13 natural gas utilities that have actively traded stocks and forecasted financial data. We use natural gas utilities that derive at least 50 percent of their revenue from regulated rates. These utilities have market power and are influenced significantly by economic regulation. As explained below, the model results based on natural gas utilities are adjusted to reflect the risks faced by Florida WAW utilities.

This Commission approved the current leverage formula in 2011 by Order No. PSC-11-0287-PAA-WS.[4] In 2012 through 2016 we continued to use the 2011 leverage formula for establishing the authorized ROE for WAW utilities. [5,6,7,8,9] In 2012 through 2016, we found that the range of returns on equity derived from the annual leverage formulas were not optimal for determining the appropriate authorized ROE for WAW utilities due to Federal Reserve monetary policies that resulted in historically low interest rates. Consequently, this Commission decided it was reasonable to continue using the range of returns on equity of 8.74 percent to 11.16 percent from the 2011 leverage formula docket.

Section 367.081(4)(f), F.S., authorizes this Commission to establish a range of returns for setting the authorized ROE for WAW utilities. However, use of the leverage formula by the

---

[3]Order No. PSC-08-0846-FOF-WS, issued December 31, 2008, in Docket No. 080006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

[4]Order No. PSC-11-0287-PAA-WS, issued July 5, 2011, in Docket No. 110006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

[5]Order No. PSC-12-0339-PAA-WS, issued June 28, 2012, in Docket No. 120006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

[6]Order No. PSC-13-0241-PAA-WS, issued June 3, 2013, in Docket No. 130006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

[7]Order No. PSC-14-0272-PAA-WS, issued May 29, 2014, in Docket No. 140006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

[8]Order No. PSC-15-0259-PAA-WS, issued July 2, 2015, in Docket No. 150006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

[9]Order No. PSC-16-0254-PAA-WS, issued June 29, 2016, in Docket No. 160006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

utilities is discretionary and a utility can file cost of equity testimony in lieu of using the leverage formula. This Commission may set an ROE for WAW utilities based on record evidence in any proceeding. If a utility files cost of equity testimony, this Commission will determine the appropriate ROE based on the evidentiary record in that proceeding.

We have jurisdiction pursuant to Section 367.081, F.S.

Decision

The current leverage formula approved by this Commission in Order No. PSC-16-0254-PAA-WS shall continue to be used until the leverage formula is readdressed in 2018 and a workshop shall be scheduled for the fall of 2017 to review and update, if necessary, the methodology used to determine the leverage formula. Accordingly, the leverage formula is as follows:

Return on Common Equity = 7.13% + (1.610 ÷ Equity Ratio)

Where the Equity Ratio = Common Equity ÷ (Common Equity + Preferred Equity + Long-Term and Short-Term Debt)

Range: 8.74% @ 100% equity to 11.16% @ 40% equity

Additionally, we shall cap returns on common equity at 11.16 percent for all WAW utilities with equity ratios less than 40 percent. We believe this will discourage imprudent financial risk. This cap is consistent with the methodology we used in Order No. PSC-08-0846-FOF-WS.

Section 367.081(4)(f), F.S., authorizes this Commission to establish a leverage formula to calculate a reasonable range of returns on common equity for WAW utilities. We must establish this leverage formula not less than once a year. For administrative efficiency, the leverage formula is used to determine the appropriate return for an average Florida WAW utility. Traditionally, we have applied the same leverage formula to all WAW utilities. As is the case with other regulated companies under our jurisdiction, this Commission has discretion in the determination of the appropriate ROE based on the evidentiary record in any proceeding. If one or more parties file testimony in opposition to the use of the leverage formula, this Commission will determine the appropriate ROE based on the evidentiary record in that proceeding.

Methodology

The leverage formula relies on two ROE models. We adjusted the results of these models to reflect differences in risk and debt cost between the index of companies used in the models and the average Florida WAW utility. Both models include a four percent adjustment for flotation costs. The models are as follows:

- A Discounted Cash Flow (DCF) model applied to an index of natural gas utilities that have publicly traded stock and are followed by the Value Line Investment Survey (Value Line). This DCF model is an annual model and uses prospective growth rates.

- The updated index consists of five natural gas companies that derive at least 50 percent of their total revenue from gas distribution service. These companies have a median Standard and Poor's bond rating of A.

- A Capital Asset Pricing Model (CAPM) using a market return for companies followed by Value Line, the average yield on the Treasury's long-term bonds projected by the Blue Chip Financial Forecasts, and the average beta for the index of natural gas utilities. The market return for the 2017 leverage formula was calculated using a quarterly DCF model with stock prices as of April 14, 2017.

Consistent with Order No. PSC-01-2514-FOF-WS,[10] we averaged the indicated returns of the above models and adjusted the result as follows:

- A bond yield differential of 62 basis points is added to reflect the difference in yields between an A/A2 rated bond, which is the median bond rating for the natural gas utility index, and a BBB-/Baa3 rated bond. Florida WAW utilities are assumed to be comparable to companies with the lowest investment grade bond rating, which is Baa3. This adjustment compensates for the difference between the credit quality of "A" rated debt and the credit quality of the minimum investment grade rating.

- A private placement premium of 50 basis points is added to reflect the difference in yields on publicly traded debt and privately placed debt, which is illiquid. Investors require a premium for the lack of liquidity of privately placed debt.

- A small utility risk premium of 50 basis points is added because the average Florida WAW utility is too small to qualify for privately placed debt.

After the above adjustments, the resulting cost of equity estimate is included in the average capital structure for the natural gas utilities.

Updated Leverage Formula

In the instant docket, we updated the leverage formula using the most recent 2017 financial data and our previously approved methodology.

Using the updated financial data in the leverage formula decreases the lower end of the current allowed ROE range by 104 basis points and decreases the upper end of the range by 40 basis points. Overall, the spread between the range of returns on equity based on the updated leverage formula is 306 basis points (7.70 percent to 10.76 percent). In comparison, the spread in

[10]Order No. PSC-01-2514-FOF-WS, issued December 24, 2001, in Docket No. 010006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity of water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

the range of returns on equity for the existing leverage formula is 242 basis points (8.74 percent to 11.16 percent). The 306 basis point spread reflected in the updated leverage formula is significantly greater than the 20-year average spread of 206 basis points.

The inflated ROE spread relative to the 2011 leverage formula is caused by the low bond rates resulting from the Federal Reserve's various monetary policies and quantitative easing programs. In its press release dated May 3, 2017, the Federal Reserve stated:[11]

> Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The Committee views the slowing in growth during the first quarter as likely to be transitory and continues to expect that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace, labor market conditions will strengthen somewhat further, and inflation will stabilize around 2 percent over the medium term. Near-term risks to the economic outlook appear roughly balanced. The Committee continues to closely monitor inflation indicators and global economic and financial developments.
>
> In view of realized and expected labor market conditions and inflation, the Committee decided to maintain the target range for the federal funds rate at 3/4 to 1 percent. The stance of monetary policy remains accommodative, thereby supporting some further strengthening in labor market conditions and a sustained return to 2 percent inflation.
>
> […In light of the current shortfall of inflation from 2 percent,] the Committee will carefully monitor actual and [expected progress toward its inflation goal.] The Committee expects that economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run. However, the actual path of the federal funds rate will depend on the economic outlook as informed by incoming data.

The most recent assumed Baa3 bond rate of 5.66 percent used in the updated leverage formula calculation, which includes a 50 basis point adjustment for small company risk and a 50 basis point adjustment for a private placement premium, remains low relative to historic levels. In comparison, the assumed Baa3 bond rate used in the existing leverage formula is 7.13 percent.

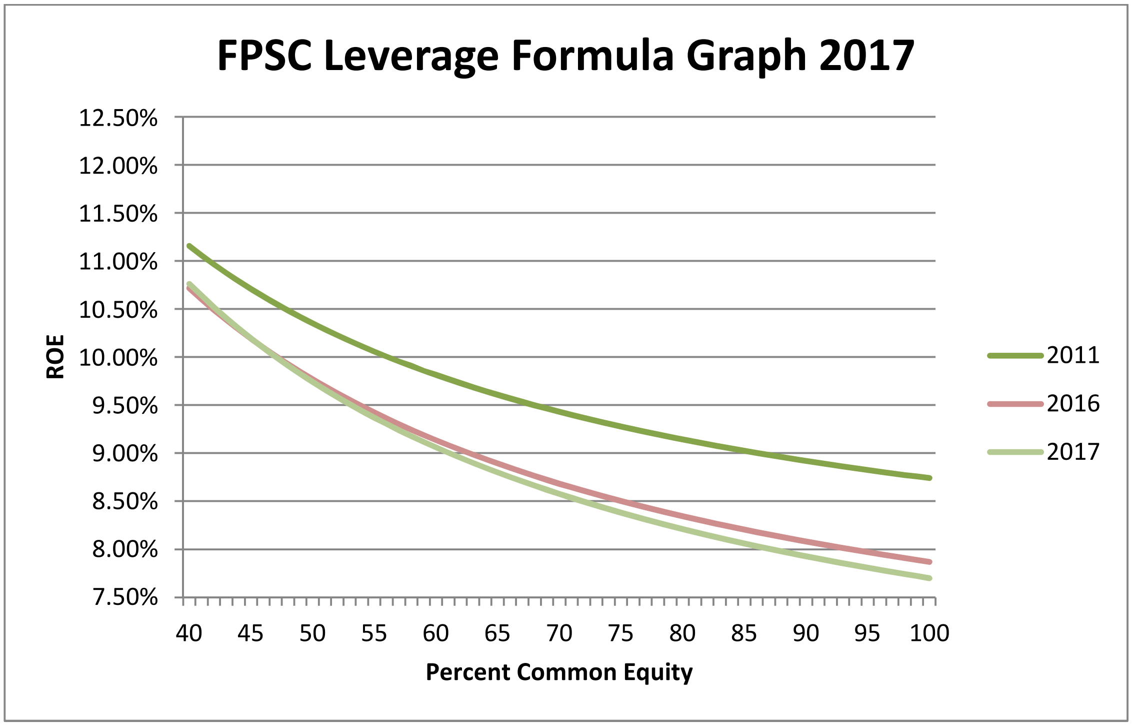
Because interest rates are at historically low levels, thereby increasing the slope of the leverage formula relative to prior years, we find that the range of returns on equity produced from the updated leverage formula is not optimal for determining the appropriate authorized ROE for Florida WAW utilities at this time. An increase in the slope of the leverage formula means a given change in the equity ratio will result in a greater change to the cost of equity. The results of this year's leverage formula produced a slope consistent with the slopes produced by

---

[11] See Federal Reserve System, Statement of the Federal Open Market Committee on May 3, 2017, available at https://www.federalreserve.gov/newsevents/pressreleases/monetary20170503a.htm

financial data for 2012 through 2016. As shown below, Chart 1 illustrates the change in the slope of the leverage formula using updated data compared to the current leverage formula.

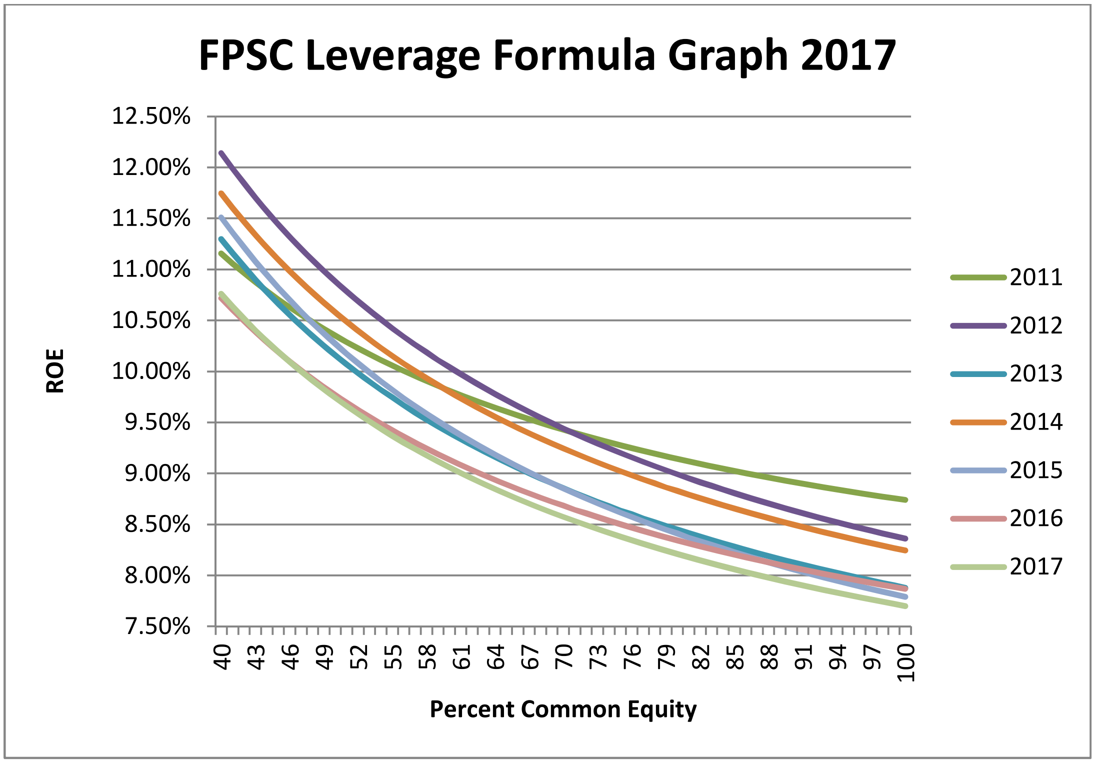
Chart 1
Comparison of Annual Leverage Formulas



Source: FPSC Analysis

Chart 2 illustrates the change in the slope of the leverage formula for the seven years 2011 through 2017.

Chart 2
Comparison of Annual Leverage Formulas since 2011



Source: FPSC Analysis

In 2016, by Order No. PSC-16-0254-PAA-WS, issued June 29, 2016, this Commission continued to use the leverage formula initially approved in 2011. This Commission kept the 2011 leverage formula in place because Federal Reserve monetary policies lowered interest rates to historically low levels, thereby increasing the slope of the leverage formula graph relative to previous years. The Federal Reserve's monetary policies and resulting capital market conditions that existed in 2012 through 2017 are expected to continue in 2018.[12]

Conclusion

This Commission finds that the existing leverage formula range of 8.74 percent to 11.16 percent initially approved in 2011 is still reasonable for WAW utilities. We find that retaining the use of the current in-place leverage formula until the leverage formula is addressed again in 2018 is a reasonable alternative to updating the formula using current 2017 financial information.

---

[12]See Federal Reserve System, Statement of the Federal Open Market Committee on May 3, 2017, available at https://www.federalreserve.gov/newsevents/pressreleases/monetary20170503a.htm

We continue to find that the leverage formula is a sound, workable methodology that reduces the costs and administrative burdens in WAW rate cases by eliminating the need for cost of equity testimony. However, along with changes in market conditions, mergers and acquisitions have affected the number of natural gas companies included in the proxy group. In 2008, the leverage formula consisted of 10 natural gas companies, in comparison, only five companies currently meet the established criteria to be included in the proxy group. A workshop shall be scheduled for the fall of 2017 to evaluate and update the companies comprising the comparable group and to investigate whether or not to revise the current leverage formula.

Based on the aforementioned, we find that the current leverage formula approved by this Commission in Order No. PSC-16-0254-PAA-WS shall continue to be used until the leverage formula is readdressed in 2018 and that a workshop shall be scheduled for the fall of 2017 to review and update, if necessary, the methodology used to determine the leverage formula.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the current leverage formula approved by this Commission in Order No. PSC-16-0254-PAA-WS, Return on Common Equity = 7.13% + (1.610 ÷ Equity Ratio), shall continue to be used until the leverage formula is readdressed in 2018. A workshop shall be scheduled for the fall of 2017 to review and update, if necessary, the methodology used to determine the leverage formula. It is further

ORDERED that the current range of returns on common equity of 8.74 percent to 11.16 percent is hereby approved for water and wastewater utilities as set forth in this Order. It is further

ORDERED that the returns on common equity shall be capped at 11.16 percent for all water and wastewater utilities with equity ratios less than 40 percent. It is further

ORDERED that Attachment 1 is incorporated herein by reference. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the “Notice of Further Proceedings” attached hereto. It is further

ORDERED that this docket shall remain open to allow Commission staff to monitor changes in capital market conditions and to readdress the reasonableness of the leverage formula as conditions warrant.

By ORDER of the Florida Public Service Commission this 26th day of June, 2017.

Carlotta S. Stauffer

CARLOTTA S. STAUFFER
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

MAD

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing that is available under Section 120.57, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on July 17, 2017.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this/these docket(s) before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

Attachment 1

SUMMARY OF RESULTS
2017 Water & Wastewater Leverage Formula

(A) DCF ROE for Natural Gas Index	8.25%
(B) CAPM ROE for Natural Gas Index	9.40%
AVERAGE	8.83%
Bond Yield Differential	0.57%
Private Placement Premium	0.50%
Small-Utility Risk Premium	0.50%
Adjustment to Reflect Required Equity Return at a 40% Equity Ratio	0.76%
Cost of Equity for Average Florida WAW Utility at a 40% Equity Ratio	11.16%

Authorized Formula

Return on Common Equity	=	7.13%	+	(1.610	÷	Equity Ratio)
Range of Returns on Equity	=	8.74%	to	11.16%		

$$k_p = \frac{\text{div}}{P}$$

where k_p = The cost of preferred stock
div = The promised dividend on the preferred stock
P = The market price of the preferred stock

If the current market price is not available, use yields on similar-quality issues as an estimate. For a fixed-life or callable preferred stock issue, estimate the opportunity cost by using the same approach as for a comparable debt instrument. In other words, estimate the yield that equates the expected stream of payments with the market value. For convertible preferred issues, option-pricing approaches are necessary.

STEP 3: ESTIMATE THE COST OF EQUITY FINANCING

The opportunity cost of equity financing is the most difficult to estimate because we can't directly observe it in the market. We recommend using the capital asset pricing model (CAPM) or the arbitrage pricing model (APM). Both approaches have problems associated with their application, including measurement difficulty. Many other approaches to estimating the cost of equity are conceptually flawed. The dividend yield model (defined as the dividend per share divided by the stock price) and the earnings-to-price ratio model substantially understate the cost of equity by ignoring expected growth.

The Capital Asset Pricing Model

The CAPM is discussed at length in all modern finance texts (for example, see Brealey and Myers, 1999, or Copeland and Weston, 1992).[6] These detailed discussions will not be reproduced here. (In this section, we assume that you are generally familiar with the principles that underlie the approach.) The CAPM postulates that the opportunity cost of equity is equal to the return on risk-free securities plus the company's systematic risk (beta) multiplied by the market price of risk (market risk premium). The equation for the cost of equity (k_s) is as follows:

[6] T. Copeland and J. Weston, *Financial Theory and Corporate Policy*, 3rd ed. (Reading, MA: Addison-Wesley, 1992); and R. Brealey and S. Myers, *Principles of Corporate Finance*, 5th ed. (New York: McGraw-Hill, 1999).

$$k_s = r_f + [E(r_m) - r_f]\,(\text{beta})$$

where r_f = The risk-free rate of return
$E(r_m)$ = The expected rate of return on the overall market portfolio
$E(r_m) - r_f$ = The market risk premium
beta = The systematic risk of the equity

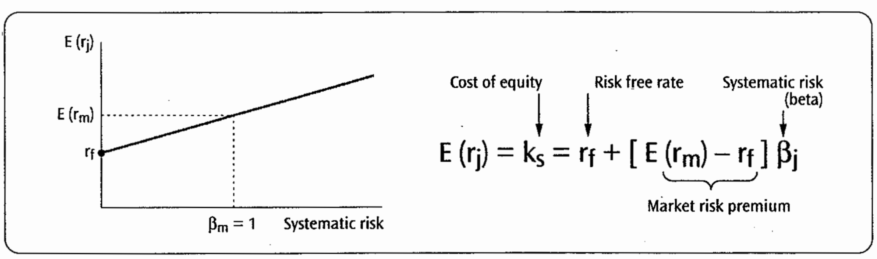
The CAPM is illustrated in Exhibit 10.3. The cost of equity, k_s, increases linearly as a function of the measured undiversifiable risk, beta. The beta for the entire market portfolio is 1.0. This means that the average company's equity beta will also be about 1.0. It is very unusual to observe a beta greater than 2.0 or less than 0.3. The market risk premium (the price of risk) is measured as the slope of the CAPM line in Exhibit 10.3, that is, the slope is $E(r_m) - r_f$.

To carry out the CAPM approach, we need to estimate the three factors that determine the CAPM line: the risk-free rate, the market risk premium, and the systematic risk (beta). The balance of this section describes a recommended approach for estimating each.

Determining the risk-free rate Hypothetically, the risk-free rate is the return on a security or portfolio of securities that has no default risk and is completely uncorrelated with returns on anything else in the economy. In theory, the best estimate of the risk-free rate would be the return on a zero-beta portfolio, constructed of long and short positions in equities in a way that produces the minimum variance zero-beta portfolio. Because of the cost and complexity of constructing minimum variance zero-beta portfolios, they are not practical for estimating the risk-free rate.

We have three reasonable alternatives that use government securities: the rate for Treasury bills, the rate for 10-year Treasury bonds, and the rate

Exhibit 10.3 The Capital Asset Pricing Model



by interest payments; preferred stockholders are compensated by fixed dividend payments; and the firm's remaining income belongs to its common stockholders and serves to "pay the rent" on stockholders' capital. Management may either pay out earnings in the form of dividends or retain earnings for reinvestment in the business. If part of the earnings is retained, an *opportunity cost* is incurred: Stockholders could have received those earnings as dividends and then invested that money in stocks, bonds, real estate, and so on. *Thus, the firm should earn on its retained earnings at least as much as its stockholders themselves could earn on alternative investments of equivalent risk.*

What rate of return can stockholders expect to earn on other investments of equivalent risk? The answer is k_s, because they can earn that return simply by buying the stock of the firm in question or that of a similar firm. Therefore, if our firm cannot invest retained earnings and earn at least k_s, then it should pay those earnings to its stockholders so that they can invest the money themselves in assets that do provide a return of k_s.

Whereas debt and preferred stocks are contractual obligations which have easily determined costs, it is not at all easy to estimate k_s. However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive—no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company's cost of equity, we generally use all three methods and then choose among them on the basis of our confidence in the data used for each in the specific case at hand.

SELF-TEST QUESTIONS

What are the two types of common equity whose costs must be estimated?

Explain why there is a cost for retained earnings.

THE CAPM APPROACH

As we saw in Chapter 5, the Capital Asset Pricing Model is based on some unrealistic assumptions, and it cannot be empirically verified. Still, because of its logical appeal, the CAPM is often used in the cost of capital estimation process.

Under the CAPM we assume that the cost of equity is equal to the risk-free rate plus a risk premium that is based on the stock's beta coefficient and the market risk premium as set forth in the Security Market Line (SML) equation:

$$\begin{aligned} k_s &= \text{Risk-free rate} + \text{Risk premium} \\ &= k_{RF} + (k_M - k_{RF})b_i. \end{aligned}$$

Given estimates of (1) the risk-free rate, k_{RF}, (2) the firm's beta, b_i, and (3) the required rate of return on the market, k_M, we can estimate the required rate of return of return on the firm's stock, k_s. This required return can then be used as an estimate of the cost of retained earnings.

ESTIMATING THE RISK-FREE RATE

The starting point for the CAPM cost of equity estimate is k_{RF}, the risk-free rate. There is really no such thing as a truly riskless asset in the U.S. economy. Treasury securities are free of default risk, but long-term T-bonds will suffer capital losses if interest rates rise, and a portfolio invested in short-term T-bills will provide a volatile earnings stream because the rate paid on T-bills varies over time.

Since we cannot in practice find a truly riskless rate upon which to base the CAPM, what rate should we use? Our preference—and this preference is shared by most practitioners—is to use the rate on long-term Treasury bonds. Here are our reasons:

1. Capital market rates include a real, riskless rate (generally thought to vary from 2 to 4 percent) plus a premium for inflation which reflects the expected inflation rate over the life of the security, be it 30 days or 30 years. The expected rate of inflation is likely to be relatively high during booms and low during recessions. Therefore, during booms T-bill rates tend to be high to reflect the high current inflation rate, whereas in recessions T-bill rates are generally low. T-bond rates, on the other hand, reflect expected inflation rates over a long period, so they are far less volatile than T-bill rates.

2. Common stocks are long-term securities, and although a particular stockholder may not have a long investment horizon, most stockholders do invest on a long-term basis. Therefore, it is reasonable to think that stock returns embody long-term inflation expectations similar to those embodied in bonds rather than the short-term expectations in bills. Therefore, the cost of equity should be more highly correlated with T-bond rates than with T-bill rates.

3. Treasury bill rates are subject to more random disturbances than are Treasury bond rates. For example, bills are used by the Federal Reserve System to control the money supply, and bills are also used by foreign governments, firms, and individuals as a temporary safe haven for money. Thus, if the Fed decides to stimulate the economy, it drives down the bill rate, and the same thing happens if trouble erupts somewhere in the world and money flows into U.S. dollars seeking safety. T-bond rates are also influenced by Fed actions and by international money flows, but not to the same extent as T-bill rates. This is another reason why T-bill rates are more volatile than T-bond rates and, most experts agree, more volatile than k_s.

4. T-bills are essentially free of price risk, but they are exposed to a relatively high degree of reinvestment rate risk. Long-term investors such as pension funds and life insurance companies are as concerned about reinvestment rate risk as price risk. Therefore, most long-term investors would feel equally exposed to risk if they held bills or bonds.

5. When the CAPM is used to estimate a particular firm's cost of equity over time, bond rates produce more reasonable results. When T-bill rates were low in 1977

156 FERC ¶ 61,234
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, and Tony Clark.

Association of Businesses Advocating Tariff Equity Docket No. EL14-12-002
Coalition of MISO Transmission Customers
Illinois Industrial Energy Consumers
Indiana Industrial Energy Consumers, Inc.
Minnesota Large Industrial Group
Wisconsin Industrial Energy Group

v.

Midcontinent Independent System Operator, Inc.
ALLETE, Inc.
Ameren Illinois Company
Ameren Missouri
Ameren Transmission Company of Illinois
American Transmission Company LLC
Cleco Power LLC
Duke Energy Business Services, LLC
Entergy Arkansas, Inc.
Entergy Gulf States Louisiana, LLC
Entergy Louisiana, LLC
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Entergy Texas, Inc.
Indianapolis Power & Light Company
International Transmission Company
ITC Midwest LLC
Michigan Electric Transmission Company, LLC
MidAmerican Energy Company
Montana-Dakota Utilities Co.
Northern Indiana Public Service Company
Northern States Power Company-Minnesota
Northern States Power Company-Wisconsin
Otter Tail Power Company
Southern Indiana Gas & Electric Company

OPINION NO. 551

ORDER ON INITIAL DECISION

(Issued September 28, 2016)

Paragraph Numbers

1. This order addresses briefs on and opposing exceptions to an Initial Decision issued on December 22, 2015 by the presiding Administrative Law Judge (Presiding Judge) in the captioned proceedings.[1] The Initial Decision set forth the Presiding Judge's findings concerning a complaint filed pursuant to section 206 of the Federal Power Act (FPA)[2] challenging the Midcontinent Independent System Operator, Inc. (MISO) Transmission Owners' (TOs) base return on equity (ROE) reflected in MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff). In this order, we affirm the Initial Decision.

I. Background

2. On September 23, 2002, the Commission affirmed an initial decision that approved a base ROE of 12.38 percent for MISO TOs, but the Commission modified the initial decision to include an upward adjustment of 50 basis points for turning over operational control of transmission facilities.[3] On remand from the U.S. Court of Appeals for the District of Columbia Circuit, among other things, the Commission vacated its prior order concerning the 50 basis point adder and stated that MISO TOs may make filings under section 205 of the FPA to include an incentive adder.[4] The 12.38 percent base ROE continues to be the applicable ROE under Attachment O of the MISO Tariff used by all MISO TOs except for American Transmission Company, LLC (ATC).[5]

---

[1] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. System Operator, Inc.*, 153 FERC ¶ 63,027 (2015) (Initial Decision).

[2] 16 U.S.C. § 824e (2012).

[3] *Midwest Indep. Transmission Sys. Operator, Inc.*, 100 FERC ¶ 61,292 (2002), *order denying reh'g*, 102 FERC ¶ 61,143 (2003).

[4] *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,355 (2005).

[5] ATC's base ROE of 12.2 percent was established as part of a settlement agreement that was filed with the Commission on March 26, 2004. In Docket No. ER04-108-000, the Commission approved the uncontested settlement. *Am. Transmission Co. LLC*, 107 FERC ¶ 61,117 (2004).

3. On November 12, 2013, Complainants[6] filed a complaint (Complaint) alleging that the current base ROE is unjust and unreasonable. Additionally, Complainants argued that the capital structures of certain MISO TOs feature unreasonably high amounts of common equity and that MISO TOs' capital structures should be capped at 50 percent common equity. Finally, Complainants contended that the ROE incentive adders received by ITC Transmission for being a member of a regional transmission organization (RTO) and by both ITC Transmission and Michigan Electric Transmission Company, LLC (METC) for being independent transmission owners were unjust and unreasonable and should be eliminated.

4. On October 16, 2014, the Commission set for hearing the issue of whether MISO TOs' base ROE is unjust and unreasonable and established the refund effective date at November 12, 2013.[7] The Commission denied the Complaint with respect to the capital structure issue, finding that Complainants had neither demonstrated that such existing capital structures are not just and reasonable nor cited any precedent for capping, for ratemaking purposes, the level of common equity in such capital structures for individual utilities, much less groups of utilities.[8] The Commission also denied the Complaint with respect to ROE incentive adders.

5. On July 21, 2016, the Commission generally denied requests for rehearing and clarification of the Hearing Order.[9] However, the Commission clarified that non-public utility transmission owners are subject to the outcome of this proceeding. Therefore, the Commission stated that, if the Commission find that MISO TOs' existing base ROE is unjust and unreasonable and requires them to amend their Attachment Os. Accordingly, the Commission will also require those non-public utility transmission owners that incorporate the existing base ROE in their rates to amend their Attachment Os to incorporate the just and reasonable base ROE on a prospective basis. However, the Commission stated that the MISO non-public utility transmission owners would only be

---

[6] Complainants, a group of large industrial customers, are: Association of Businesses Advocating Tariff Equity; Coalition of MISO Transmission Customers; Illinois Industrial Energy Consumers; Indiana Industrial Energy Consumers, Inc.; Minnesota Large Industrial Group; and Wisconsin Industrial Energy Group.

[7] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.* 149 FERC ¶ 61,049, at P 188 (2014) (Hearing Order).

[8] *Id.* P 190.

[9] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 156 FERC ¶ 61,060 (2016) (Rehearing Order).

subject to any refund obligations imposed in this proceeding to the extent they have voluntarily committed to make such refunds in prior FPA section 205 proceedings relating to the inclusion of the transmission revenue requirement in MISO's jurisdictional rates.[10]

6. On February 12, 2015, in Docket No. EL15-45-000, a different set of complainants filed a second complaint challenging the public utility MISO TOs' base ROE. By order dated June 18, 2015, the Commission set this matter for hearing and established a refund effective date of February 12, 2015, the day after the expiration of the refund period established by the Hearing Order. That refund period expired May 11, 2016.[11]

7. On December 22, 2015, in this proceeding, the Presiding Judge issued the Initial Decision finding, *inter alia*, that MISO TOs' existing 12.38 percent base ROE is unjust and unreasonable and should be reduced to 10.32 percent. The Presiding Judge also prescribed refunds, with interest, for the period from November 12, 2013 through February 11, 2015.[12] In the Initial Decision, the Presiding Judge explained that the 10.32 percent base ROE represents the midpoint of the upper half of the zone of reasonableness (upper midpoint) of 7.23 percent to 11.35 percent.[13]

---

[10] *Id.* PP 47-48.

[11] *Arkansas Elec. Coop. Corp. v. ALLETE, Inc.*, 151 FERC ¶ 61,219, at P 1 (2015) (Second Complaint Hearing Order).

[12] Initial Decision, 153 FERC ¶ 63,027 at P 491.

[13] *Id.* P 110.

8. Joint Customer Intervenors,[14] Complainants, MISO TOs,[15] Resale Power Group of Iowa (Iowa Group), and Trial Staff each filed briefs on exception and opposing exceptions to the Initial Decision. Organization of MISO States (OMS) filed a brief on exceptions and jointly filed, with Joint Consumer Advocates, a brief opposing exceptions.[16]

---

[14] Joint Customer Intervenors consist of Arkansas Electric Cooperative Corporation, Mississippi Delta Energy Agency and its members, Clarksdale Public Utilities Commission of the City of Clarksdale, Mississippi and Public Service Commission of Yazoo City, Mississippi, Hoosier Energy Rural Electric Cooperative, Inc., South Mississippi Electric Power Association, and Southwestern Electric Cooperative.

[15] MISO TOs for the purpose of this order refers to: ALLETE, Inc. for its operating division Minnesota Power (and its subsidiary Superior Water, L&P); Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois, and Ameren Transmission Company of Illinois; American Transmission Company LLC; Cleco Power LLC; Duke Energy Corporation for Duke Energy Indiana, Inc.; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Gulf States Louisiana, L.L.C.; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; Indianapolis Power & Light Company; International Transmission Company d/b/a ITC Transmission; ITC Midwest LLC; METC; MidAmerican Energy Company; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); and Wolverine Power Supply Cooperative, Inc. Intervenor Xcel Energy Services Inc. did not join certain of the MISO Transmission Owners' pleadings in this proceeding, but generally supports this brief on behalf of respondents Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation. *See* MISO TOs Brief on Exceptions at n.1.

[16] On February 10, 2016, Joint Consumer Advocates also filed a brief on exceptions, which were due on January 21, 2016. Because of its lateness, we do not consider this brief part of the record in this proceeding. *See* 18 C.F.R. § 385.711(a)(1)(i) (2016).

II. Overview of the Commission's Determinations in this Order

9. In this order, we affirm the conclusions of Initial Decision. We find the Presiding Judge correctly determined that there were anomalous capital market conditions, such that we have less confidence that the midpoint of the zone of reasonableness produced by a mechanical application of the Discounted Cash Flow (DCF) methodology satisfies the capital attraction standards of *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*[17] and *Federal Power Commission v. Hope Natural Gas Co.*[18] We affirm that, in these circumstances, the Presiding Judge reasonably considered evidence of alternative methodologies for determining ROE and the ROEs approved by state regulatory commissions, for purposes of deciding whether the MISO TOs' ROE should be set at a point above the midpoint of the DCF zone of reasonableness. That evidence corroborates our determination that an ROE above the midpoint is necessary to satisfy *Hope* and *Bluefield*. Accordingly, we find that the just and reasonable ROE for the MISO TOs should be set at the central tendency of the upper half of the zone of reasonableness. We agree with the Presiding Judge that, as a result of this analysis, the appropriate base ROE for MISO TOs is 10.32 percent. We find that the Presiding Judge correctly applied the DCF methodology, including its inclusion of TECO Energy, Inc. (TECO) in the DCF proxy group. As discussed below, we also find that MISO TOs correctly employed the expected earnings alternative, though this finding does not affect the Initial Decision's conclusion.

10. We agree with the Presiding Judge that the base ROE should not be reduced for certain MISO TOs based on their capital structure or the use of transmission formula rates. We also reject Complainants' proposed "quartile approach," as discussed below. Except where specifically mentioned herein, we affirm the determinations in the Initial Decision.

III. Discussion

A. Burden of Proof

1. Initial Decision

11. The Presiding Judge explained that, to modify a rate under FPA section 206, the Commission or complainant has the burden of showing that the existing rate is unjust and unreasonable. He also explained that a "complainant shows that a Base ROE is unjust

[17] 262 U.S. 679, 692-93 (1923) (*Bluefield*).

[18] 320 U.S. 591, 603 (1944) (*Hope*).

and unreasonable by establishing that it is higher than is necessary to meet the requirements set forth in [*Hope* and *Bluefield*]."[19] The Presiding Judge further explained that *Bluefield* dictates that the return should be "equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties."[20] Additionally, the Presiding Judge noted that the return should be "commensurate with returns on investments in other enterprises having corresponding risks."[21]

12. The Presiding Judge continued, stating that the return "should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."[22] That is, the return should be "sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital."[23]

13. Finally, the Presiding Judge stated that a base ROE that "authorized a utility to collect more than is necessary to satisfy the requirements of *Hope* and *Bluefield* would exploit consumers and, therefore, would be unjust and unreasonable," so "Complainants and other participants seeking reduction of MISO TOs' Base ROE . . . have the burden of proving that MISO TOs' Base ROE exceed that level."[24] The Presiding Judge further stated that "[i]f the evidence establishes that MISO TOs exceed [the zone of reasonableness], [Complainants] will have met their burden."[25]

2. Briefs on Exceptions

14. Joint Customer Intervenors argue that the Initial Decision is ambiguous and could be interpreted to mean that, in order to meet their burden, Complainants and aligned

---

[19] Initial Decision, 153 FERC ¶ 63,027 at P 19.

[20] *Bluefield*, 262 U.S. at 693.

[21] *Hope*, 320 U.S. at 603.

[22] *Bluefield*, 262 U.S. at 693.

[23] *Hope*, 320 U.S. at 603.

[24] Initial Decision, 153 FERC ¶ 63,027 at P 24.

[25] *Id.* P 26.

parties must establish that the ROE exceeds the zone of reasonableness.[26] Joint Customer Intervenors assert that, while such a showing would suffice to meet their burden, the ROE may also be unjust and unreasonable even if it is not outside the zone of reasonableness. Joint Customer Intervenors argues that, to find otherwise would be incorrect and inconsistent with *Martha Coakley, Mass. Attorney Gen. v. Bangor Hydro-Electric Company*,[27] and Joint Customer Intervenors take exception to the extent that the Initial Decision held an ROE must be outside the zone of reasonableness to be unjust and unreasonable.[28]

3. **Briefs Opposing Exceptions**

15. MISO TOs challenge Joint Customer Intervenors' claim. MISO TOs argue that the Presiding Judge did not need to "delve into the nuances of the burden of proof . . . and neither should the Commission."[29]

4. **Commission Determination**

16. We affirm that FPA section 206 does not require complainants or the Commission to demonstrate that an existing ROE falls outside the zone of reasonableness in order for that ROE to be considered unjust and unreasonable. The Commission disagreed with MISO TOs' identical argument in the Rehearing Order in this proceeding.[30] Moreover, as the Commission has previously concluded, not all points within the zone of reasonableness necessarily satisfy the just and reasonable standard.[31]

---

[26] Joint Customer Intervenors Brief on Exceptions at 9 (citing Initial Decision, 153 FERC ¶ 63,027 at P 26).

[27] Opinion No. 531, 147 FERC ¶ 61,234, at P 12, Opinion No. 531, Opinion No. 531-A, *order on paper hearing*, 149 FERC ¶ 61,032 (2014), Opinion No. 531-B, *order on reh'g*, 150 FERC ¶ 61,165 (2015) (citing *RITELine Ill., LLC*, 137 FERC ¶ 61,039, at P 68 (2011); *N. Pass Transmission LLC*, 134 FERC ¶ 61,095, at P 46 (2011); *S. Cal. Edison Co.*, 131 FERC ¶ 61,020, at P 51 (2010)).

[28] Joint Customer Intervenors Brief on Exceptions at 9-10.

[29] MISO TOs Brief Opposing Exceptions at 49.

[30] *See* Rehearing Order, 156 FERC ¶ 61,060 at P 17.

[31] *Id.*

B. Proxy Group and DCF Analysis

17. In order to determine the just and reasonable ROE for public utilities, the Commission applies the DCF model to a proxy group of comparable companies. The Commission uses the following standards to select the proxy group: (1) a national group of companies considered electric utilities by Value Line Investment Survey (Value Line); (2) the inclusion of companies with credit ratings no more than one notch above or below the utility or utilities whose rate is at issue; (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut during the six-month study period; (4) the inclusion of companies with no major merger activity during the six-month study period; and (5) companies whose DCF results pass threshold tests of economic logic.[32]

18. With simplifying assumptions, the formula for the DCF model reduces to: P = D/k-g, where "P" is the price of the common stock, "D" is the current dividend, "k" is the discount rate (or investors' required rate of return), and "g" is the expected growth rate in dividends. For ratemaking purposes, the Commission rearranges the DCF formula to solve for "k", the discount rate, which represents the rate of return that investors require to invest in a company's common stock, and then multiplies the dividend yield by the expression (1+.5g) to account for the fact that dividends are paid on a quarterly basis. Multiplying the dividend yield by (1+.5g) increases the dividend yield by one half of the growth rate and produces what the Commission refers to as the "adjusted dividend yield." The resulting formula is known as the constant growth DCF model and can be expressed as follows: k=D/P (1+.5g) + g. Under the Commission's two-step DCF methodology, the input for the expected dividend growth rate, "g," is calculated using both short-term and long-term growth projections.[33] Those two growth rate estimates are averaged, with the short-term growth rate estimate receiving two-thirds weighting and the long-term growth rate estimate receiving one-third weighting.[34] The Commission generally conducts the DCF analysis based on the most recent six months of financial data in the record.[35]

---

[32] Opinion No. 531, 147 FERC ¶ 61,234 at P 92.

[33] *Id.* PP 15-17, 36-40, *order on paper hearing,* Opinion No. 531-A, 149 FERC ¶ 61,032 at P 10.

[34] Opinion No. 531, 147 FERC ¶ 61,234 at PP 17, 39.

[35] *Id.* P 160.

19. In this case, the Presiding Judge determined that the DCF Study Period for calculating the zone of reasonableness should be the most recent six-month period for which there is financial data in the record, January to June 2015.[36] He rejected MISO TOs' argument that the Commission should not include data subsequent to the November 12, 2013 to February 10, 2015 refund period unless the data are "reasonably representative of the refund period."[37] While the study period utilized in Opinion No. 531 roughly coincided with the refund period, the Presiding Judge noted that that similarity is not an "essential element" of the Commission's decision to consider data outside of the refund period.[38] In any case, the Presiding Judge observed, the overlap between the study period and the refund period in Opinion No. 531 was not much greater than it is here. Lastly, the Presiding Judge noted that any ROE established as part of this proceeding is likely to apply for "an appreciable period of time outside of the Refund Period."[39] Accordingly, the best course of action is to fashion a base ROE based on the most recent data in record.

20. In order to establish a proxy group, the Presiding Judge reviewed the DCF-determined cost of equity for 42 companies. The Presiding Judge determined that 37 of those companies should be included in the proxy group. Of those companies, the lowest cost of equity was Public Service Enterprise Group's 7.23 percent and the highest cost was TECO's 11.35 percent.[40] As described in more detail below, the Presiding Judge rejected contentions that TECO should be excluded from the proxy group because of certain Merger and Acquisition (M&A) Activity. However, following Opinion No. 531, the Presiding Judge excluded three companies — Edison International, FirstEnergy Corporation (FirstEnergy), and Entergy Corporation (Entergy) — because their ROEs were less than 5.65 percent, which is 100 basis points above the average yield for public utility bonds rated Baa by Moody's.[41] The Presiding Judge also excluded Madison Gas and Electric Energy, Inc. because it did not have a credit rating from either Moody's Investors Service or S&P and, therefore, could not be shown to have a credit rating of not

[36] Initial Decision, 153 FERC ¶ 63,027 at PP 56, 61.

[37] *See* Opinion No. 531, 147 FERC ¶ 61,234 at P 64.

[38] Initial Decision, 153 FERC ¶ 63,027 at P 58.

[39] *Id.* P 61.

[40] *Id.* P 63.

[41] *Id.* PP 66-67.

more than one notch above or below MISO TOs, as required by Opinion No 531.[42] In addition, the Presiding Judge also excluded Unitil Corporation (Unitil) from the proxy group because it is not one of the companies covered by Value Line and because, unlike the companies in Value Line, Unitil has a capitalization of less than $1 billion.[43]

21. For short-term growth rates, the Presiding Judge adopted the five-year growth rates proposed by Complainants' witness, Mr. Gorman, and, for companies not included in Mr. Gorman's sample, five-year growth rates proposed by Joint Consumer Advocates' witness, Mr. Hill. Both provided projected Institutional Brokers' Estimate System (IBES) growth estimates published by *Yahoo! Finance* obtained on July 13, 2015.[44] For the long-term growth rate, the Presiding Judge adopted the 4.39 percent Gross Domestic Product (GDP) growth rate proposed by Trial Staff witness, Mr. Keyton, reasoning that his method of calculating the growth rate most closely paralleled the method that the Commission used in Opinion No. 531.[45]

22. The parties' briefs on exceptions raise two issues with respect to the Presiding Judge's rulings with respect to the proxy group and the DCF analysis of each member of the proxy group. These are: (1) whether TECO should have been excluded from the proxy group and (2) whether in future cases short-term growth projections could be based on Value Line data. We address these issues below.

1. Inclusion of TECO in the Proxy Group

23. As explained in Opinion No. 531, the Commission's practice is "to eliminate from the proxy group any company engaged in M&A activity significant enough to distort the [company's] DCF inputs" — i.e., the company's "stock prices, dividends, or growth rates."[46] TECO is the only company whose M&A activity is at issue here. We first summarize TECO's M&A activity before turning to the Initial Decision, the briefs on and opposing exceptions, and our decision whether to include TECO in the proxy group.

---

[42] *Id.* PP 70, 72 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 106).

[43] *Id.* PP 74-75, 77.

[44] *Id.* P 49.

[45] *Id.* P 44.

[46] Opinion No. 531, 147 FERC ¶ 61,234 at P 114.

24. TECO engaged in two M&A activities that could potentially require its exclusion from the proxy group. First, on September 2, 2014, nearly four months before the beginning of the updated the study period, TECO completed its acquisition of New Mexico Gas Company (New Mexico Gas).[47] The record reveals that, several months later, during the January 2015 to June 2015 study period, analysts were still assessing the impact of the New Mexico Gas acquisition on TECO earnings. For example, the May 22, 2015 issue of Value Line noted that the acquisition should increase TECO's earnings, although the acquisition was just one of several factors, including strong customer growth and impending rate increases, that Value Line identified to support the projected increase in TECO's earnings for 2015 and 2016.[48]

25. Second, on October 20, 2014, roughly a month after closing the New Mexico Gas acquisition, TECO announced an agreement to sell its coal mining subsidiary, TECO Coal Corporation (TECO Coal) to Cambrian Coal Corp. (Cambrian) for $120 million and a contingent payment of up to $50 million, depending on coal prices.[49] TECO's stock price rose approximately 8 percent in the month following news of the sale. A few months later, in February 2015, TECO announced an amendment to the terms of the agreement that lowered the purchase price to $80 million, but increased the maximum contingent payment to $60 million.[50] Later in February, a securities analyst at UBS upgraded TECO from "neutral" to "buy," noting the potential sale of TECO Coal as one of the reasons for the upgrade. Throughout this period in early 2015, IBES's growth projections for TECO increased from 6.43 percent in January to 7.08 percent in February and all the way up to 9.20 percent by March 2015, even as at least one analyst expressed skepticism that TECO would complete the sale of TECO Coal.[51]

26. In April 2015, TECO announced that it was considering selling TECO Coal to other potential buyers in the event that the deal with Cambrian fell through.[52] As it happened, TECO announced in June 2015, the last month of the study period, that the deal with Cambrian had not closed as scheduled, but that it had received a non-binding

---

[47] Exh. S-4 at 12.

[48] Initial Decision, 153 FERC ¶ 63,027 at P 91; Exh. S-6 at 161.

[49] *Id.* P 98; Exh. S-3.

[50] *Id.* P 98. The terms of the sale were amended again in mid-April 2015.

[51] *Id.* P 101; Exh. S-4 at 15; S-6 at 147, 171.

[52] Initial Decision, 153 FERC ¶ 63,027 at P 99.

offer for TECO Coal from an undisclosed buyer. The IBES growth projections remained steady at 9.20 percent throughout April, May, and June, notwithstanding the multiple reports casting doubt on TECO's ability to complete the sale of TECO Coal.[53] In early July 2015, TECO announced that it had failed to reach an agreement with the undisclosed buyer, but that a sale of TECO Coal to Cambrian remained a possibility. A week later, on July 13, 2015, IBES's growth projection for TECO declined to 7.68 percent.[54] The Presiding Judge used the 7.68 percent IBES growth projection in his DCF analysis of TECO.

a. <u>Initial Decision</u>

27. The Presiding Judge rejected the contentions of Complainants, Joint Customer Intervenors, Iowa Group, and Trial Staff that TECO should be excluded from the proxy group.[55] The Presiding Judge concluded that neither the acquisition of New Mexico Gas nor the attempted sale of TECO Coal was sufficient to "distort" the DCF inputs.[56] Beginning with the New Mexico Gas acquisition, the Presiding Judge concluded that any earnings distortion caused by the acquisition was insufficient to exclude TECO. As an initial matter, the Presiding Judge noted that Mr. Gorman, the "principal advocate" of excluding TECO on the basis of its acquisition of New Mexico Gas, did not advocate that position in his original testimony in February 2015, but altered his position to advocate exclusion of TECO in his updated testimony in July 2015.[57] The Presiding Judge, however, concluded that the updated information on which Mr. Gorman relied did not suggest that TECO should be excluded from the proxy group. In particular, the Presiding Judge determined that Mr. Gorman was "incorrect" to suggest that TECO's IBES growth rate had increased 280 basis points between his original and updated testimony. The Presiding Judge observed that, although it was true that the IBES growth rate estimate increased from 6.43 percent in January 2015 to 9.20 percent in June 2015, that number had declined to 7.68 percent by the time of Mr. Gorman's updated testimony, meaning

---

[53] *Id.* P 101; Exh.S-6 at 149, 151.

[54] Initial Decision, 153 FERC ¶ 63,027 at P 101. The Presiding Judge's Order Establishing Procedural Schedule provided that the cut-off date for data to be used by any party in updates of ROE studies would be July 13, 2015. Exh. JCA-22. *See also infra* note 88.

[55] Initial Decision, 153 FERC ¶ 63,027 at PP 79, 81.

[56] *Id.* PP 81, 96, 106.

[57] *Id.* P 82.

that the actual increase in the growth rate was just 125 basis points, less than half of the 280-basis-point increase to which Mr. Gorman testified.[58]

28. In addition, the Presiding Judge determined that Mr. Gorman's characterization of the May 2015 Value Line report was also "inaccurate."[59] The Presiding Judge noted that TECO's acquisition of New Mexico Gas was just one of many factors that led Value Line to increase its projection for TECO's 2015 earnings. As the Presiding Judge explained, Value Line also emphasized the strong growth prospects for TECO's Florida utilities and an anticipated reduction in TECO's cost of debt. The Presiding Judge also noted that Value Line's increased earnings projections for 2016 were not based on the acquisition of New Mexico Gas. Instead, the Presiding Judge concluded that that increase was based on a pending rate increase for one of TECO's Florida utilities and on New Mexico Gas's own growth projections, whose sustainability was not called into question by the evidence in the record.[60] The Presiding Judge also concluded that, because the acquisition's effect on earnings was limited to 2015, there was no reason to conclude that the acquisition would have an effect on the IBES "Next 5 Years" of growth projections, which is the basis for the DCF analysis.[61] The Presiding Judge rejected arguments that the purchase of New Mexico Gas had decreased short-term earnings expectations relative to the long-term expectations to the point of "distort[ing]" the DCF input, as the Commission to exclude a proxy company on the basis of merger activity.[62]

29. The Presiding Judge also declined to exclude TECO on the basis of its attempted sale of TECO Coal. Although concluding that the "efforts to sell TECO Coal affected investors' perceptions of TECO," the Presiding Judge nevertheless concluded that this effect did not rise to the level of a distortion.[63] The Presiding Judge noted that, throughout the study period, TECO's projected growth rate increased even as the prospects of completing the sale of TECO Coal diminished. The Presiding Judge thus concluded that the growth projections for TECO "do not appear to have been related in

---

[58] *Id.* P 90.

[59] *Id.* P 91.

[60] *Id.* PP 94-96.

[61] *Id.* PP 95-96.

[62] *Id.* PP 90-95.

[63] *Id.* PP 100, 106.

any way to" the efforts to sell TECO Coal.[64] In addition, the Presiding Judge recognized that, in the months after the agreement to sell TECO Coal to Cambrian, TECO's stock price increased 20 percent while the industry average decreased 2 percent.[65] Based on that divergence, the Presiding Judge concluded that the potential sale of TECO Coal "may have distorted [TECO's] dividend yield downward during the study period."[66] However, the Presiding Judge declined to exclude TECO, reasoning that, because TECO was at the upper end of the zone of reasonableness and because the divestiture efforts appeared to have lowered TECO's cost of equity, to exclude TECO would have the effect of correcting a distortion that lowered the upper bound of the zone of reasonableness by *further lowering* the upper bound of the zone.[67] That result, the Presiding Judge concluded, would make the DCF analysis a "less reliable" guide to determining TECO's cost of equity.[68] Finally, the Presiding Judge also asserted that the sale of a business unit — or, in this case, an attempted sale — is neither a merger nor an acquisition and, therefore, should not be a reason to exclude a company based on M&A activity.

b. <u>Briefs on Exception</u>

30. Complainants, Joint Customer Intervenors, and Trial Staff contend that the Presiding Judge should have excluded TECO. Joint Customer Intervenors contend that the Presiding Judge erred when he decided not to exclude TECO on the basis that it was at the top of the zone of reasonableness and that the M&A activity appeared to depress TECO's dividend yield. Joint Customer Intervenors also argue that Commission precedent requires the exclusion of any company that engages in significant M&A activity, regardless of its position in the zone of reasonableness or what effect that activity appeared to have on the DCF inputs, including the dividend yield.[69] Joint Customer Intervenors also contend that the Presiding Judge erred to the extent that he declined to exclude TECO on the basis that "[a] sale of a unit (much less an attempted

---

[64] *Id.* P 103.

[65] *Id.* P 104.

[66] *Id.* P 106.

[67] *Id.* P 107.

[68] *Id.* P 108.

[69] Joint Customer Intervenors Brief on Exceptions at 12; Trial Staff Brief on Exceptions at 13-14.

sale) is neither a merger nor an acquisition."[70] Joint Customer Intervenors aver that a sale is a form of M&A activity—since some company is acquiring the asset being sold—and that it "defies logic" to exclude a company that purchases an asset from the proxy group, but not exclude the company that sells it.[71] Similarly, Joint Customer Intervenors argue that the fact that the sale was not completed is irrelevant as the Commission has "routinely" excluded companies from the proxy group based on contemplated or attempted merger or acquisition activity.

31. Complainants contend that the Presiding Judge erred to the extent that he declined to exclude TECO in part because TECO's acquisition of New Mexico Gas occurred several months before the beginning of the January-June 2015 updated study period on which the Initial Decision relied.[72] Complainants defend Mr. Gorman's decision to include TECO based on the original study period, but exclude TECO based on the updated study period. They argue that, although TECO both acquired New Mexico Gas and announced the agreement to sell TECO Coal during the initial study period, which covered July-December, 2014, those activities "were perceived by investors as having only a modest impact on TECO's earnings" during that period and, therefore, Mr. Gorman reasonably decided to include TECO in the proxy group.[73] Complainants contend that during the updated study period, by contrast, there was evidence that the acquisition would have a more significant impact on TECO's earnings. In particular, Complainants point to the fact that Value Line stated that TECO's earnings were likely to increase "considerably" and listed the New Mexico Gas acquisition as one of the reasons for that prediction.[74] Complainants contend that this change in earnings expectations justified Mr. Gorman's decision to change course and exclude TECO from the proxy group. In addition, Complainants take exception to how the Presiding Judge interpreted Value Line's discussion of the factors affecting TECO's earnings. Although

---

[70] Joint Customer Intervenors Brief on Exceptions at 12; Trial Staff Brief on Exceptions at 14-15 (observing that a sale was sufficient to trigger a company's exclusion in Opinion No. 531).

[71] Complainants Brief on Exceptions at 14.

[72] *Id.* at 13.

[73] *Id.* at 13-14.

[74] *Id.* at 15-17. Complainants also briefly suggest that TECO should have been excluded on the basis of its attempts to sell TECO Coal. They note that TECO's stock price increased 8 percent when it announced the sale of TECO Coal. Trial Staff makes a similar point. Trial Staff Brief on Exceptions at 13.

Complainants acknowledge that there were multiple factors contributing to TECO's growth estimates, they assert that these additional factors affecting the growth do not nullify the effect of the acquisition, which they argue is sufficient to exclude TECO.[75]

32. In addition, Complainants argue that the Presiding Judge erred by concluding that Value Line's earnings forecast limited the impact of the New Mexico Gas acquisition to 2015.[76] They contend that, although Value Line discussed the acquisition's impact on 2015 earnings, it never stated that that the effects of the acquisition were limited to 2015. Complainants further contend that Value Line's discussion of the factors contributing to earnings growth in 2016 were "additional factors"—i.e., over and above those affecting the 2015 earnings—that is, they were not the only factors affecting the 2016 earnings projections. In any case, Complainants argue, the Presiding Judge wrongly concluded that the 2015 earnings projections were not included in the IBES five-year growth projections. Consequently, they contend, the Presiding Judge erred in concluding that the New Mexico Gas acquisition did not affect the IBES five-year growth projections used in the DCF analysis.[77]

33. Finally, Complainants assert that the Presiding Judge erroneously discounted Mr. Gorman's testimony on the basis that the IBES growth rate projection for TECO had increased only 125 basis points, rather than the 277 basis points that Mr. Gorman testified to. Complainants contend that Mr. Gorman's calculation was correct as of July 13, 2015, when he downloaded the information from *Yahoo! Finance* and, therefore, and that the Initial Decision was wrong to conclude that the projected growth rate had increased only 125 basis points. In any case, they argue, a 125-basis-point increase still represents a meaningful change in TECO's estimated growth rate.

34. Trial Staff echoes many of these arguments regarding TECO Coal. In particular, Trial Staff contends that the Presiding Judge failed to adequately justify the conclusion that changes in TECO's stock price, estimated growth rate, and other investment measures were not related to the sale of TECO Coal.[78]

---

[75] Complainants Brief on Exceptions at 20-21.

[76] *Id.* at 18.

[77] *Id.* at 19-20.

[78] Trial Staff Brief on Exceptions at 13.

c. **Briefs Opposing Exception**

35. MISO TOs contend that the Presiding Judge properly included TECO in the proxy group. They argue that the Commission's screening criteria require a company's exclusion on the basis of M&A activity only when (1) that activity takes place during the study period and (2) that activity is sufficient enough to distort the inputs for the DCF analysis.[79] Because the acquisition of New Mexico Gas took place outside the updated study period, MISO TOs assert that it does not meet the first criterion for being excluded on the basis of M&A activity. In addition, MISO TOs contend that there were several factors affecting TECO's estimated growth rate and, therefore, it is not clear whether the effects of the New Mexico Gas acquisition had a significant effect on the estimated growth rates. MISO TOs also contend that the Presiding Judge correctly concluded that the change in TECO's estimated growth rate was 125 basis points, not the 280 basis points that Mr. Gorman testified to.[80] In any case, they argue, investors did not react significantly to this information and the stock price remained within "a narrow band" during the study period.[81]

36. Turning to the sale of TECO Coal, MISO TOs contend that any distortion associated with the attempted sale would have occurred when the sale was first announced, which was before the updated study period.[82] In addition, they state that there was little variation between TECO's stock prices and those of the Dow Jones Utility Average, suggesting that whatever effect the attempted sale had on TECO's stock price was minimal.[83] MISO TOs also assert that the Presiding Judge correctly determined that the attempted sale did not significantly affect TECO's IBES growth rates or Value Line's earnings per share (EPS) estimates—a result that MISO TOs contend is not surprising given that TECO Coal accounts for less than 1.5 percent of TECO's market capitalization.[84]

---

[79] MISO TOs Brief Opposing Exceptions at 38.

[80] *Id.* at 41.

[81] *Id.* at 42.

[82] *Id.* at 43.

[83] *Id.* at 44-45.

[84] *Id.* at 47.

d. Commission Determination

37. We affirm the Presiding Judge's decision to include TECO in the proxy group. As explained in Opinion No. 531, it is the Commission's "practice . . . to eliminate from the proxy group any company engaged in M&A activity significant enough to *distort* the DCF inputs."[85] We do not exclude a company simply because it has engaged in any M&A activity or that activity may cause changes in the DCF inputs.[86] Rather, we exclude a company if the M&A activity may cause temporary changes in DCF inputs that are not sustainable or representative of longer-term investor expectations for the company. For the reasons that follow, we conclude that neither TECO's acquisition of New Mexico Gas nor TECO's attempted sale of TECO Coal constitutes M&A activity sufficient to distort the DCF inputs.

38. We begin with New Mexico Gas. As noted, TECO's acquisition of New Mexico Gas was completed on September 2, 2014, nearly four months before the beginning of the updated study period, which covered January-June, 2015.[87] As such, speculation about whether the acquisition would be completed could not have affected, much less distorted, the stock price or the other DCF inputs during the updated study period. Nevertheless, Complainants contend that TECO should be excluded on the grounds that the acquisition of New Mexico Gas created a temporary and unsustainable increase in TECO's expected earnings. We disagree. As an initial matter, we find that, over the course of the updated study period, the IBES growth estimates increased 125 basis points, not 280 basis points that Mr. Gorman testified to.[88] However, as illustrated by the July 13, 2015 *Yahoo!*

---

[85] Opinion No. 531, 147 FERC ¶ 61,234 at P 114 (emphasis added).

[86] *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129, at PP 67-68 (2006) ("We also reject [the] . . . argument that Commission precedent supports, in every instance, the exclusion from a proxy group of any utility engaged in merger activity."), *order on reh'g*, 122 FERC ¶ 61,265, *order on clarification*, 124 FERC ¶ 61,136 (2008).

[87] Initial Decision, 153 FERC ¶ 63,027 at PP 80, 84.

[88] Exh. JC-22 at 7. Complainants contend that there is a disputed issue of fact regarding the appropriate growth rate for TECO at the end of the updated study period. Complainants Brief on Exceptions at 21-22. They assert that Mr. Gorman's testimony, in which he states that TECO's growth rate increased by 280 basis points from its 6.43 percent level in January 2015, implies a growth rate of 9.20 percent as of the end of the study period, while Join Consumer Advocates' witness, Mr. Hill, stated that he used a growth rate of 7.68 percent. *Id.* We affirm the Presiding Judge's decision to rely on Mr. Hill's 7.68 percent growth rate. Mr. Hill's testimony states clearly that he relied upon the numbers from *Yahoo! Finance* on July 13, 2015, the cut-off date for ROE data

(continued...)

Finance data included along with the testimony of Mr. Hill, the actual growth projected earnings growth for TECO at the end of the updated study period used in the parties' DCF analysis was 7.68 percent, 125 basis points above the 6.43 percent at the beginning of the study period.

39. We conclude that there is no evidence in the record suggesting that the New Mexico Gas acquisition caused a significant and unsustainable increase in TECO's earnings expectations during the updated study period. The May 22, 2015 Value Line report suggests that the acquisition will increase earnings "over and above" the savings TECO will realize from no longer paying transaction costs associated with the acquisition. There is nothing suggesting that the additional increase is unsustainable. After all, all other things being equal, an earnings increase is what we would expect when a company increases its regulated gas and electric customers by 50 percent, as TECO did in acquiring New Mexico Gas.[89] In any case, the acquisition was just one of many factors, along with rate increases for TECO's Florida utilities and an anticipated reduction in TECO's cost of debt, that supported Value Line's increased earnings

---

used in the updated study period, to evaluate TECO's merger activity. *See* Exh. JCA-22; Order Establishing Procedural Schedule, Docket No. EL14-12, at 3 (Jan. 23, 2015). Mr. Gorman, by contrast, does not state when he compiled the growth rate data on which he relied in deciding to exclude TECO. Exh. JC-22 at 7. Although, later in his testimony, Mr. Gorman stated that he used data taken from *Yahoo! Finance* on July 13, 2015 to perform the DCF analysis, *id.* at 8, that analysis did not include TECO, as Mr. Gorman had already determined to exclude TECO from the proxy group. *See* Exh. JC-25; Exh. JC-22 at 7. As a result, there is nothing in Mr. Gorman's testimony that suggests that he used July 13, 2015 IBES data – and not data from earlier in the study period, when the IBES growth rate was 9.20 percent, Exh. S-4 at 15 – when deciding whether to exclude TECO from the proxy group. Accordingly, we agree with the Presiding Judge that the 7.68 percent growth rate used by Mr. Hill represents the more reliable figure and more clearly represents "the most recent record evidence of the growth rates actually expected by the investment community." Opinion No. 531, 147 FERC ¶ 61,234 at P 89.

[89] *See* Joint Customer Intervenors Brief on Exceptions at 12. To the extent that the parties suggest that TECO should be excluded because its earnings outlook improved because it is no longer incurring the transaction cost associated with the acquisition, we reject their argument. Adopting that position would require that the Commission exclude companies for a year after almost any major merger or acquisition as the savings from no longer incurring the transaction costs materialize in annual earnings. That result is not the purpose of the M&A screen.

projections.[90] The Value Line report thus is not evidence suggesting that the acquisition distorted TECO's expected growth rate based on temporary, short-term developments that are unlikely to continue.

40. Turning to TECO's attempts to sell TECO Coal, we similarly conclude that there is no evidence suggesting that those efforts "distorted" the DCF inputs. Unlike the acquisition of New Mexico Gas, the efforts to sell TECO extended into the updated study period and, therefore, it is possible that speculation related to the potential merger could have affected TECO's DCF inputs. Nevertheless, we conclude that any effect was either too small or too attenuated to rise to the level of a distortion requiring TECO's exclusion from the proxy group.

41. We find that the record does not show that the attempted sale of TECO Coal distorted TECO's expected earnings. We first note that TECO Coal represents less than 1.5 percent of TECO's total market capitalization.[91] The sale of such a relatively small asset is, as a general matter, not the type of input-distorting transaction that the M&A screen is intended to address. Additionally, many of the public utilities, especially relatively large companies that make a good comparison for TECO, are regularly engaged in potential mergers or acquisitions of small business units or subsidiaries. Excluding such companies from the proxy group on the basis of any small purchase or sale would unnecessarily shrink the group of representative companies, thereby making the proxy group, and the resulting DCF analysis, a less reliable tool for ensuring that the allowed ROE satisfies the requirements of *Hope* and *Bluefield*.

42. In this case, the evidence confirms that TECO's potential sale of its underperforming asset, TECO Coal, had little impact on its projected growth rates or stock prices. As the Presiding Judge observed, IBES's projected growth rates for TECO steadily increased throughout the first five months of the six-month study period, even as the prospects for selling TECO Coal steadily deteriorated.[92] If the potential sale of TECO Coal was a significant factor affecting TECO's DCF inputs, we would anticipate

---

[90] Initial Decision, 153 FERC ¶ 63,027 at P 91.

[91] Exh. MTO-23 at 99 (valuing TECO Coal using the most recent non-contingent purchase price for the attempted sale to Cambrian). Although it is of course possible that the expected earnings growth rate would have further increased during this period were it not for the eroding chances of a successful sale of TECO Coal, we conclude that there is no evidence in the record suggesting that the decreasing likelihood of a sale provided any such drag on TECO's earnings expectations.

[92] Initial Decision, 153 FERC ¶ 63,027 at P 103.

at least some decline in the expected growth rate as the prospects for a sale deteriorated between February and June, 2015. Instead, as noted, TECO's expected growth rate first increased between February and March and then held steady through June.[93] In short, the record simply does not suggest that the potential sale had much, if any, effect on the growth rate used in the DCF analysis.

43. Similarly, we conclude that there is no evidence in the record that the attempted sale of TECO Coal caused a distortion in TECO's stock price. The comparison of TECO's stock price versus the Dow Jones Utility Average submitted by Dr. Avera[94] shows that the two moved in near lockstep from November 2014 through April 2015, which significantly overlaps with the study period. In any case, Dr. Avera's graph shows that TECO outperformed the industry average by an even greater amount for much of March and April, 2015, when the chances of a successful sale appeared to be diminishing.[95] Once again, if the potential sale of TECO Coal was affecting TECO's DCF inputs in any significant way, we would not expect to see TECO's stock price performing well relative to the industry average even as the prospects for the sale declined. Although it might be argued that looking at relative performance is somewhat misleading, and that TECO's stock would have performed consistently worse relative to the industry average were it not for the potential sale, there is no evidence in the record suggesting that that is the case here and our M&A screen does not require a company's exclusion from the proxy group on so speculative a basis.[96]

---

[93] *Id.* P 101.

[94] Exh. MTO-23 at 99.

[95] The Presiding Judge did not rely on Dr. Avera's chart because the y-axis for TECO's stock price was smaller relative to the y-axis for the industry average, which, according to the Presiding Judge, caused Dr. Avera's chart to underrepresent the variation in TECO's stock price. That observation does not require us to change our conclusion, which rests in part on the fact that TECO's performed better relative to the industry average when the prospects for the sale dimmed, than when the sale appeared most likely to occur.

[96] Although there is evidence in the record that some analysts viewed TECO Coal as "a drag on shares" of TECO, Initial Decision, 153 FERC ¶ 63,027 at P 100, that evidence does not suggest that the increasingly dim prospect of eliminating that "drag" was sufficient to "distort" the DCF inputs, especially given the absence of any apparent correlation between the DCF inputs and the prospects for a successful sale of TECO Coal.

2. Short-term Growth Projection

a. Initial Decision

44. The Presiding Judge adopted IBES short-term growth rates published by *Yahoo! Finance* obtained on July 13, 2015 for each proxy company that was included in the proxy group of at least one participant.[97] The Presiding Judge further stated that the Commission has "long relied on IBES growth projections as evidence of the growth rates expected by the investment community" and that since the discontinuation of the IBES Monthly Data Book in 2008, it has consistently used the IBES growth rate estimates published by *Yahoo! Finance* as the source of analysts' consensus growth rates.[98]

45. Additionally, the Presiding Judge stated that he did not need to address the arguments MISO TOs made in support of use of Value Line growth rates because "one can only use one set of growth rates" and the "decision . . . based on the most recent data available actually dictates the use of IBES growth rates" because they were the only data presented for the DCF study period.[99]

b. Briefs on Exceptions

46. MISO TOs do not except to the Presiding Judge's use of IBES short-term growth projections in his DCF analysis of the companies included in the proxy group in this proceeding. However, they argue that the Commission should confirm that, in future proceedings as warranted by the surrounding facts and circumstances, the growth projections published by Value Line constitute an acceptable and comparable source of short-term earnings growth estimates that may be considered for use in the two-step DCF analysis.

47. MISO TOs state that MISO TOs' witness, Dr. Avera offered alternative two-step DCF studies using the IBES short-term growth estimates, as published by *Yahoo! Finance* and Value Line short-term estimates.[100] MISO TOs state that Dr. Avera's studies relied exclusively on data from the six-month period ending on January 31, 2015 (the Refund Period). All other DCF studies entered into evidence by opposing parties,

---

[97] Initial Decision, 153 FERC ¶ 63,027 at P 44.

[98] *Id.* P 46.

[99] *Id.* PP 48-49.

[100] MISO TOs Brief on Exceptions at 13.

whether developed for the Refund Period or the updated six-month period ending in June 2015, used IBES growth forecasts. Hence, the record contains no Value Line short-term growth estimates for the updated six-month period ending in June 2015, which the Presiding Judge used for his DCF analysis.[101] For this reason, MISO TOs state that the Presiding Judge found that his decision to evaluate the base ROE using the updated DCF study period "actually dictates use of IBES growth rates," given the record's absence of Value Line growth rates for the Update Period.[102]

48. MISO TOs request that the Commission unequivocally announce that the Initial Decision includes no merits determination regarding the appropriateness of using Value Line growth estimates in the two-step DCF methodology in public utility cases.[103] In the alternative, MISO TOs conditionally except to this aspect of the Initial Decision to ensure that this case is not interpreted as disqualifying comparable sources of short-term growth rates, including Value Line, in future proceedings.[104]

49. In support, MISO TOs argue that, as recently as Opinion No. 531, the Commission has stated that "there may be more than one valid source of growth rate estimates" and stated that, in applying the two-step DCF methodology, the "short-term growth estimate will be based on the five-year projections reported by IBES (or a comparable source)."[105] MISO TOs argue that a number of witnesses challenged the comparability of Value Line but that the Initial Decision did not address these arguments given that no party introduced Value Line data into the proceeding to determine the short-term growth rate for the Update Period.[106]

50. MISO TOs also argue that record evidence demonstrates the comparability of Value Line growth data as both IBES and Value Line projections are expressed on an EPS basis and neither "can be endorsed as systematically more reliable than the other."[107]

---

[101] *Id.* at 13.

[102] *Id.* at 14 (citing Initial Decision, 153 FERC ¶ 63,027 at P 49).

[103] *Id.* at 14.

[104] *Id.* at 14.

[105] *Id.* at 15.

[106] *Id.* at 15-16.

[107] *Id.* at 16.

Additionally, MISO TOs argue that no party disputes that Value Line's growth rate estimates: (1) have a wide financial community circulation; (2) reflect projections from reputable financial analysts that develop short-term growth rate estimates; (3) are reported to investors on a timely basis; and (4) are used by institutions and other investors. For these reasons, MISO TOs argue that Value Line's forecasts satisfy the comparability requirement articulated in Opinion No. 531.[108]

51. Furthermore, MISO TOs argue that previous applications of the DCF Formula using IBES growth estimates do not preclude the future use of Value Line growth estimates or undercut their reliability. In support of this position, MISO TOs point out that Value Line is a "trusted and reputable source for investment data" because it is a "widely-followed, independent investor service."[109] Additionally, MISO TOs argue that the record discredits any attempt to disqualify Value Line growth estimates as "not strictly forward looking."[110] They further argue that the Value Line user guide explains that Value Line's projections are "of growth for each item for the coming 3 to 5 years" and that it is not a detriment to inform investors of Value Line's starting point for measuring the rate of change.[111]

52. MISO TOs state that opposing parties' suggest that the Commission disqualified Value Line growth data for use in the two-step DCF methodology when, in prior proceedings, the Commission rejected proposals to use estimates from different sources for different proxy companies and/or to average IBES data with Value Line growth estimates.[112] MISO TOs argue that these cases do not involve the explicit issue that MISO TOs hope to clarify here. MISO TOs also dispute the claim that the Value Line's EPS estimates are attributable to a single analyst. They point out that, in Opinion No. 531-B, the Commission stated that it would not rely on "an analyst head-count" to evaluate the relative reliability of data sources.[113]

---

[108] *Id.* at 18 (citing Opinion No. 531 at P 102).

[109] *Id.* at 18-19.

[110] *Id.* at 19.

[111] *Id.* at 19-20.

[112] *Id.* at 21.

[113] *Id.* at 22.

53. MISO TOs also dispute opposing parties' attempts to show that Value Line's estimates are less current than IBES's, arguing instead that Value Line reports its estimates on a timely basis and updates them regularly.[114] MISO TOs also ask the Commission to make explicit that the EPS growth forecasts published by Value Line and IBES are presumed to be comparable, and that the source of short-term growth data to be used in any future application of the two-step DCF model will be determined on a case-by-case basis.[115]

c. Briefs Opposing Exceptions

54. Complainants, OMS/Joint Consumer Advocates, Joint Customer Intervenors, Iowa Group, and Trial Staff agree with the Presiding Judge's adopting IBES as the source of short-term growth rate data for this case. Complainants argue that the Presiding Judge's adoption of the five-year IBES growth rate presented by Mr. Gorman's analysis, as supplemented by the IBES data from Mr. Hill's DCF analysis, relies on the Commission's rationale for adopting IBES growth rate projections, as outlined in Opinion No. 531. Complainants state that the Commission has "long relied on IBES growth rate projections as evidence of the growth rates expected by the investment community."[116]

55. Complainants also disagree with MISO TOs' argument that neither IBES nor *Value Line* should be presumed more reliable than the other.[117] Complainants ask the Commission to dismiss this argument as moot because Value Line growth data was absent for the time period adopted by the Initial Decision. Similarly, Joint Customer Intervenors argue that addressing MISO TOs' exception here would have no impact on this proceeding, and would only influence what may or may not be appropriate in future scenarios with different facts and circumstances.[118]

56. In a similar vein, OMS/Joint Consumer Advocates state that what MISO TOs really seek is in the nature of a declaratory order, i.e., a Commission pronouncement

---

[114] *Id.* at 22-23.

[115] *Id.* at 23.

[116] Complainants Brief Opposing Exceptions at 5 (citing Initial Decision, 153 FERC ¶ 63,027 at P 46).

[117] *Id*. (citing MISO TOs Brief on Exceptions at 16-18).

[118] Joint Customer Intervenors Brief Opposing Exceptions at 17-18.

applicable to unspecified future cases.[119] OMS/Joint Consumer Advocates state that the Commission's rules provide other more suitable vehicles for parties to request such broad statements of generic policy, including Rule 207(a)(2), which authorizes the filing of petitions for "[a] declaratory order . . . to . . . remove uncertainty."[120] Iowa Group also characterizes the MISO TOs' request for clarification as a collateral attack on Opinion Nos. 531 and 531-B.[121]

57. OMS/Joint Consumer Advocates further state that MISO TOs are disingenuous in suggesting that the Presiding Judge rejected reliance on Value Line's short-term earnings growth rates only out of necessity, rather than based on a finding that the IBES growth rates were shown to be preferable on the merits. OMS/Joint Consumer Advocates contend that the latest Value Line reports for the adopted study period were in fact in the record for all relevant companies,[122] and, if it had been appropriate, the Presiding Judge would have used those reports' short term EPS growth rates as DCF inputs.[123] OMS/Joint Consumer Advocates state that the Commission should reject MISO TOs' request that the Commission declare that "the EPS growth forecasts published by Value Line and IBES, if available for all proxy companies, are presumed to be comparable."[124] OMS/Joint Consumer Advocates and Joint Customer Intervenors assert that Value Line's short-term earnings growth rates are patently not comparable to IBES growth rates, in multiple respects.[125] For example, OMS/Joint Consumer Advocates and Joint Customer Intervenors state that, unlike the IBES forecasts, the Value Line EPS forecasts "consist[] of an earnings estimate of only one analyst."[126] OMS/Joint Consumer Advocates also

[119] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 14 (citing MISO TOs Brief on Exceptions at 23).

[120] *Id.* at 14 (citing 18 C.F.R. § 385.207(a)(2) (2016)).

[121] Iowa Group Brief Opposing Exceptions at 8 (citing MISO TOs Brief on Exception at 14).

[122] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 11 (citing Exh. S-6 at 9-55).

[123] *Id.*

[124] *Id.* at 15 (citing MISO TOs Brief on Exceptions at 23).

[125] Joint Customer Intervenors Brief Opposing Exceptions at 5.

[126] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 15 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 72 n.145; Joint Customer Intervenors Brief

(continued...)

state that IBES short-term growth projections are based on analysts' independent evaluation of prospective growth and not inherently tied to past performance. By contrast, OMS/Joint Consumer Advocates state that Value Line forecasts start from an earnings baseline that starts more than three years in the past.[127] Trial Staff also state that the "ANNUAL RATES" section Value Line data used by MISO TOs' witness, Dr. Avera, are plainly from a past three-year period to a future three-year period.[128] OMS/Joint Consumer Advocates state that, because Value Line's EPS forecasts are derived from an historical three-year baseline, those estimates will be an especially poor predictor of future EPS growth.[129] In addition, OMS/Joint Consumer Advocates state that IBES updates its consensus forecast whenever there is a change in the forecast of one of its polled analysts, whereas Value Line publishes its estimates on a fixed schedule (once every three months).[130] OMS/Joint Consumer Advocates argue that at any given point in time, the IBES consensus forecast is more likely to reflect the most up to date information.[131]

58. Additionally, OMS/Joint Consumer Advocates state that Value Line's forecasts are not consistent with the Commission's decision in Opinion No. 531 to "change the way DCF analyses are conducted in public utility cases to use *the same methodology* as the Commission uses in natural gas and oil pipeline cases."[132] OMS/Joint Consumer Advocates state that Value Line's partially retrospective growth rate is not used in

---

Opposing Exceptions at 5 (citing Exh. JCI-4 at 21:10-14).

[127] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 16 (citing Exh. JCA-11 at 10-12; Exh. JCI-4 at 19-20; Exh. S-1 at 79-82).

[128] Trial Staff Brief Opposing Exceptions at 8 (citing Tr. 622:10; Exh. S-1 at 80-81).

[129] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 16.

[130] *Id.* (citing Exh. JCI-4 at 21:17 – 22:3).

[131] *See also* Joint Customer Intervenors Brief Opposing Exceptions at 5-6 (citing Exh. JCI-4 at 21:10-14; Opinion No. 531, 147 FERC ¶ 61,234 at P 88).

[132] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 17 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 32 (emphasis supplied)).

pipeline cases, where the precedents specifically reject using Value Line reports to test the reasonableness of projected growth rates.[133]

59. OMS/Joint Consumer Advocates and Trial Staff oppose MISO TOs' request for a case-by-case determination of the short-term growth rate forecast data source.[134] According to OMS/Joint Consumer Advocates and Iowa Group, MISO TOs' proposal would enable litigants to select whichever source of short-term growth rate data is most advantageous for a given study period.[135] Joint Customer Intervenors go further, arguing that MISO TOs chose the Value Line growth rates because they were the most advantageous source of short-term growth rates.[136]

60. In addition, OMS/Joint Consumer Advocates state that, if the Commission grants the relief that MISO TOs request, the Commission should put some boundaries around the data source debate in the future.[137] Specifically, OMS/Joint Consumer Advocates state that the Commission should provide guidance as to how it will apply the new rules in future cases.[138] Joint Customer Intervenors also argue that, while MISO TOs portray IBES as just one among many potential sources of growth rate estimates, it is only appropriate to use a comparable source of short-term growth estimates where IBES growth rate estimates are not available.[139] Iowa Group offers that in Opinion No. 531 the Commission applied exactly the same two-step DCF model that it has used for

---

[133] *Id.*

[134] *Id.* at 18 (citing Initial Decision, 153 FERC ¶ 63,027 at P 48); Trial Staff Brief Opposing Exceptions at 43-44.

[135] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 19 (citation omitted); Iowa Group Brief Opposing Exceptions at 11; *see also* Joint Customer Intervenors Brief Opposing Exceptions at 7.

[136] *Id.* at 7-8.

[137] Joint Customer Intervenors also express concern about the lack of boundaries here by pointing out that MISO TOs propose no criteria for judging whether a particular source is comparable. *Id.* at 7.

[138] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 20.

[139] Joint Customer Intervenors Brief Opposing Exceptions at 7.

twenty years to set returns on equity for gas and oil pipelines to electric transmission utilities. Iowa Group explains that in doing so, the Commission relied on oil and gas pipeline precedent that established its preference for IBES short-term growth rates.[140]

61. Trial Staff states that it is not the Initial Decision that states IBES estimates are "preferable" – it is the Commission's statements and actions over many years that indicate that preference.[141] Trial State further contends that the Commission has never for any purpose used the particular data from the "ANNUAL RATES" section of the Value Line company reports, which are the basis of Dr. Avera's earnings growth input.[142]

d. Commission Determination

62. We reject MISO TOs' request for clarification that the growth projections published by Value Line constitute an acceptable and comparable source of short-term earnings growth estimates that may be considered for use in the two-step DCF analysis. In Opinion No. 531, the Commission held that "in future public utility cases, the Commission will adopt the same two-step DCF methodology it uses in natural gas and oil pipeline cases."[143] While the Commission has refrained from mandating the exclusive use of IBES data in its natural gas and oil pipeline rate of return cases, the Commission has stated that "IBES data is the preferred data source for computing the short-term growth rate."[144] The Commission has explained that the "IBES data is a compilation of projected growth rates from various knowledgeable financial advisors within the investment community."[145] As such, the IBES short-term growth estimates generally represent consensus growth rate estimates by a number of analysts. By contrast, the Commission has rejected the use of Value Line growth estimates in gas pipeline ROE

---

[140] Iowa Group Brief Opposing Exceptions at 8-9.

[141] Trial Staff Brief Opposing Exceptions at 6.

[142] *Id.* at 8 citing Tr. 621:20-622:2.

[143] Opinion No. 531, 147 FERC ¶ 61,234 at P 39.

[144] *Nw. Pipeline Corp.*, 92 FERC ¶ 61,287, at 62,002 (2000). *See also Nw. Pipeline, Corp.*, 79 FERC ¶ 61,309, at 62,385 (1997) (finding that "[t]he IBES figures should be used for the short-run growth rate of reach of the proxy companies.").

[145] *See, e.g.*, *Northwest Pipeline Corp.*, 87 FERC ¶ 61,266, at 62,058-62,059 (1999); *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260, at P 234 (2002).

cases, because they are the estimates of a single analyst and thus do not constitute such consensus estimates.[146]

63. MISO TOs suggest that, despite the Commission's refusal to use Value Line short-term growth estimates in natural gas and oil pipeline ROE cases, the Commission intended in Opinion No. 531 to permit the use of Value Line estimates in public utility ROE cases. They rely heavily on the Commission's statement in Opinion No. 531 that the "short-term growth estimate will be based on the projections reported by IBES (or comparable source)."[147] Opinion No. 531 provided a more extensive discussion of short-term growth rates after the general statement relied on by the MISO TOs. There, the Commission stated that the "growth rates used in the DCF model should be the growth rates expected by the market" and that the Commission "has long relied on IBES growth projections as evidence of the growth rates expected by the investment community."[148] The Commission also addressed a proposal by Trial Staff to use Reuters Estimates Database (RED) growth projections published by *reuters.com* for those companies in the proxy group for which the IBES growth projection only reflected the view of one analyst.[149] Trial Staff argued the RED growth projections should be used because they were consensus estimates reflecting the views of more than one analyst. The Commission, however, rejected this proposal because Trial Staff had not provided RED growth projections for all the companies in the proxy group, while IBES data for all the proxy companies was available in the record.[150] While the Commission stated that it is willing to allow the substitution of "comparable data," the Commission explained that "an alternative source of growth rate data should only be used when that source can be used for the growth projections of all of the proxy group companies" because using different sources could "produce skewed results, because those sources may take

---

[146] *Northwest Pipeline Corp.*, 87 FERC at 62,058-62,059; and *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at P 234. *See* Opinion No. 531-B, 150 FERC ¶ 61,165 at n.145, stating that the Value Line data "for any company consists of an earnings estimate from only one analyst, rather than consensus estimates."

[147] Opinion No. 531, 147 FERC ¶ 61,234 at P 39.

[148] *Id.* PP 89-90.

[149] *Id.* P 90.

[150] *Id.*

different approaches to calculating growth rates."[151] For this reason, the Commission emphasized that it has "consistently used a single investor service such as IBES for the investment analysts' growth rate estimates."[152]

64. Thus, consistent with the discussion in Opinion No. 531, the Commission is willing to use short-term growth data published by a source comparable to IBES. However, because the Commission requires the use of analysts' consensus growth rates as the short-term growth rate input in the DCF methodology, only data sources that publish analysts' consensus growth rate estimates, such as the RED growth forecasts at issue in Opinion No. 531, can be considered comparable to IBES.[153] Value Line does not publish such consensus growth rate estimates. We believe that investors, particularly larger institutional investors such as mutual funds and pension funds, are far more likely to rely upon published consensus estimates than they are to rely on Value Line. In addition, published consensus estimates sourced from investment analysts, e.g., IBES's growth rate estimates, are updated on a rolling basis, sometimes as frequently as daily, and are therefore superior to Value Line's growth rate estimates, which are updated only on a lagging, quarterly basis.[154] We therefore decline to grant MISO TOs' request that we presume that the short-term growth forecasts published by Value Line and IBES to be comparable.

65. Accordingly, we affirm the Presiding Judge's holdings concerning the proxy group and the DCF analysis of each proxy company. We therefore affirm the Presiding Judge's finding that the zone of reasonableness for establishing MISO TOs' ROE is from 7.23 percent to 11.35 percent. We now turn to the issue of where within that range to set the MISO TOs' ROE.

---

[151] *Id.* (citing to *ISO New England, Inc.*, 109 FERC ¶ 61,147, at P 205 (2004) (finding that a presiding judge is not precluded from finding candidates for inclusion in the proxy group for which comparable data can reasonably be substituted for the growth rate data reported by IBES or Value Line)).

[152] *Id.*

[153] *See, e.g.*, *id.* P 89.

[154] While we find that Value Line's *growth rate estimates* are not acceptable as the short-term consensus growth rate input for the two-step DCF model, we reiterate that Value Line is a valid source of general financial data and affirm that Value Line estimates and financial data (e.g., betas) are acceptable as inputs for alternative cost of equity methodologies.

C. Placement of the Base ROE within the Zone of Reasonableness

66. The Commission has typically set the base ROE in RTO/ISO cases at the midpoint of the zone of reasonableness.[155] However, in Opinion No. 531, the Commission found that, because of the presence of anomalous capital market conditions in that case, the central tendency of the zone of reasonableness produced by a mechanical application of the DCF methodology would not satisfy the requirements of *Hope*[156] and *Bluefield*.[157] Opinion No. 531 corroborated that finding by reference to several alternative methodologies for determining the cost of equity. The Commission accordingly concluded that the just and reasonable ROE in that case should be set at the midpoint of the upper half of the zone of reasonableness.

67. Below, we first consider whether the Presiding Judge correctly held that there are anomalous capital market conditions in this case that would justify setting MISO TOs' ROE above the midpoint produced by a mechanical application of the DCF analysis. Because we affirm the Presiding Judge's conclusion that there were anomalous market conditions, we proceed to consider whether the relevant alternative methodologies corroborate that the mechanical application of the DCF analysis does not result in an ROE consistent with *Hope* and *Bluefield*. Based on the record in this case, including the presence of unusual capital market conditions, we conclude that the just and reasonable base ROE for MISO TOs should be set at the midpoint of the upper half of the zone of reasonableness.[158] Based on the DCF study adopted by the Presiding Judge, we affirm the Presiding Judge's finding that the just and reasonable base ROE for MISO TOs is 10.32 percent.

---

[155] *See S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 91, remanded on other grounds sub nom. *S. Cal. Edison Co. v. FERC*, 717 F.3d 177 (2013).

[156] *Hope*, 320 U.S. 591.

[157] *Bluefield*, 262 U.S. at 693.

[158] We calculate the midpoint of the upper half of the zone as follows: (1) calculate the midpoint of the full zone of reasonableness; (2) define the upper half of the zone of reasonableness as the range of cost of equity estimates that are bounded, on the low end, by the midpoint of the full zone of reasonableness and, on the high end, by the highest cost of equity result among the proxy group companies; and (3) calculate the midpoint of the cost of equity results in that upper range, inclusive of the endpoints.

1. Anomalous Market Conditions

a. Initial Decision

68. The Presiding Judge determined that it is MISO TOs' burden to show that anomalous capital market conditions justify selecting an ROE above the midpoint of the zone of reasonableness.[159] The Presiding Judge explained that this showing required evidence that (1) anomalous conditions make it difficult to determine whether an ROE set at the midpoint of the zone of reasonableness reflects the risks facing MISO TOs and (2) other points of comparison, including credible alternative valuation models and the ROEs allowed by state public utility commissions support an ROE above the midpoint of the zone.

69. The Presiding Judge determined that anomalous market conditions existed during the study period and that these conditions complicated the task of assessing whether an ROE at the midpoint of the zone of reasonableness accurately reflected the risks facing MISO TOs.[160] The Presiding Judge determined that the Federal Reserve's "unprecedented" purchases of debt securities were the primary factor driving the reduction in short-term interest rates and, as a result, causing a reduction in the dividend yields of public utility stocks. The Presiding Judge concluded that these circumstances are unique and, in all likelihood, unsustainable and temporary because they depend on the Federal Reserve's actions to depress interest rates. The Presiding Judge also found that investors expected the Federal Reserve to allow interest rates to "normalize."[161]

70. The Presiding Judge concluded that these conditions—and the depressed interest rates in particular—had rendered the DCF model less reliable. The Presiding Judge explained that the DCF model assumes that, under normal conditions, an investor will evaluate a stock by considering the anticipated flow of future dividends, discounted for risk, that would accrue to owners of that stock.[162] However, the Presiding Judge concluded that, during the study period, investors were not abiding by the DCF model's assumptions. Instead, the Presiding Judge determined that the Federal Reserve's actions had reduced the returns on debt securities to a level that investors "find unacceptable,"

---

[159] Initial Decision, 153 FERC ¶ 63,027 at P 120.

[160] *Id.* P 219.

[161] *Id.* P 224.

[162] *Id.* P 226.

causing them to move their money into other classes of assets, including electric-utility stocks.[163]

71. The Presiding Judge concluded that these investors were basing their purchasing decisions "solely [on] the current yields of those stocks" and not on the present value of future dividends, as the DCF model assumes. The Presiding Judge further concluded that investors were making these decisions notwithstanding their belief that the expected rise in interest rates would inevitably cause these stocks to decline in value. The Presiding Judge further concluded that these "hot money," short-term investors would, therefore, liquidate their positions in these stocks once they "sense" that the Federal Reserve has begun to allow conditions to normalize, causing a significant decline in their price.[164] As a result, the Presiding Judge concluded that, during the study period, the interest of hot money investors had caused electric-utility stock prices to become inflated to a level that did "not reflect the risks that investment in these securities entails."

72. As a result of these findings, the Presiding Judge determined that the MISO TOs met their burden to show that "the evidence calls into question the reliability of the DCF analysis in this proceeding" and, by extension, whether the midpoint of the zone of reasonableness is the just and reasonable ROE for MISO TOs. Accordingly, the Presiding Judge determined that Opinion No. 531 required the consideration of alternative valuation methods and the ROEs recently authorized by state public utility commissions.[165]

b. Briefs on Exceptions

73. Complainants argue that the Presiding Judge erred in finding that anomalous market conditions existed during the relevant study period. Complainants state that Opinion No. 531 does not articulate a standard for identifying "anomalous market conditions" and that the record in this proceeding also lacks such a standard. Complainants note that the Presiding Judge, even absent evidence, extrapolates this to mean "unprecedented" and "unsustainable." Complainants contend that the Presiding Judge is unable to meet his own "unprecedented" standard because the actions of the Federal Reserve were known to investors prior to the study period.[166]

---

[163] *Id.* P 227.

[164] *Id.* PP 192, 228.

[165] *Id.* PP 229-230.

[166] Complainants Brief on Exceptions at 28-29.

74. Complainants contend that the record does not demonstrate that current market conditions impacted DCF inputs, focusing on the impact of Federal Reserve actions on investor behavior. Complainants state that the Presiding Judge implies that the Federal Reserve's actions are not reflected in financial market data, a theory which conflicts with the DCF analysis' assumption of efficient market theory.[167] Complainants argue that there is no basis to dispute that the Federal Reserve's policies are relevant information that is known to investors. Rather, current market conditions are already reflected in the DCF and have no impact on MISO TOs' capital attraction capabilities.[168]

75. Complainants contend that the Presiding Judge interprets *Hope* and *Bluefield's* capital attraction standard as applying only to long-term investors, an interpretation that is both unsubstantiated and without legal precedent.[169] Complainants also argue that the evidence in this proceeding demonstrates that such a distinction is unnecessary because the DCF model accounts for both long- and short-term investors.[170] According to Complainants, even if short-term investors do not purchase and hold, the sale price of the shares they sell remains based on the long-term cash flow expectations of that security.

76. Complainants argue that the record does not demonstrate that current market conditions negatively impacted MISO TOs' ability to attract capital. The Federal Reserve's policies, Complainants contend, have not resulted in increases to the current low capital cost environment.[171] Complainants assert that, given the indications by the Federal Reserve of gradual systematic change, no significant impact on capital markets is expected, as shown in an August 2015 *Bloomberg Businessweek* article.[172] Complainants argue that there is no immediate impetus for the Federal Reserve to modify or terminate its monetary policy such that the impact of Quantitative Easing will remain in effect for the foreseeable future.[173] Consequently, MISO TOs will continue to have access to

---

[167] *Id.* at 30 (citing Initial Decision, 153 FERC ¶ 63,027 at P 225).

[168] *Id.* at 31; *see also* Trial Staff Brief on Exceptions at 33 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 201-205).

[169] Complainants Brief on Exceptions at 31-32 (citing Initial Decision, 153 FERC ¶ 63,027 at P 207).

[170] *Id.* at 32-33 (citing Exh. JCA-11 at 25).

[171] *Id.* at 33 (citing Exh. JC-9 at 7).

[172] *Id.* at 33-34 (citing Exh. OMS-23 at 1).

[173] *Id.* at 34 (citing Exh. JC-9 at 34).

low-cost capital for the foreseeable future. Complainants also contend that the record, including statements by the Federal Reserve, undermines the Presiding Judge's finding that investors expect significant interest rate increases in the future.[174] Complainants also cite financial publications showing that investors expect interest rates to rise only gradually.[175]

77. Complainants contend that rather than relying on assertions about the actions of "hot money," the ROE should be based on the two-stage DCF analysis, without adjustments for anomalous market conditions. Complainants state that if capital market costs increase in the future such that MISO TOs' base ROE is insufficient, they may propose adjustments under section 205 of the FPA.

78. Trial Staff asserts that, while long-term interest rates are indeed low when compared to those prevailing in the recent past, they are not anomalously low when properly viewed in a longer historical context.[176] According to Trial Staff, Mr. Keyton noted that interest rates are subject to long-term cycles that can last for decades.[177] Trial Staff asserts that interest rates on 10-year U.S. Treasury bonds were under three percent during 1953, 1954 and 1955 and generally increased for almost 30 years, reaching a peak of 13.92 percent in 1981 and then receded to a level below three percent again in 2011, where they remain today.[178] Trial Staff further states that interest rates on *Moody's* Baa bonds reached a peak of 9.38 percent during the Great Depression in 1933 and generally fell for a period of 13 years, reaching a low of 3.03 percent in 1946.[179] Then, according to Trial Staff, similar to the pattern found with Treasury debt, interest rates on *Moody's* Baa bonds increased in a secular manner until reaching a peak of 16.60 percent in 1981, and subsequently began a long and steady decline, falling below five percent in 2012, where they have remained ever since.[180] Trial Staff argues that, when viewed in the context of a historical period that is long enough to capture the entirety of an interest rate

---

[174] *Id.* at 35 (citing Exh. S-15 at 10).

[175] *Id.* at 36 (citing Exh. OMS-22 at 2).

[176] Trial Staff Brief on Exceptions at 20.

[177] *Id.* at 20 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 123-141; 222).

[178] *Id.* at 20-21 (citing Exh. S-2, Schedule No. 1).

[179] *Id*. (citing Exh. S-2, Schedule No. 2).

[180] *Id.* at 21.

cycle, a view not available to the Commission in the Opinion No. 531 proceeding, the interest rates on long-term bonds during the DCF study periods in this proceeding are neither unusual nor demonstrably anomalous.

79. Trial Staff asserts that the Presiding Judge erred in relying on Paragraph 50 of Opinion No. 531-B[181] to reject Trial Staff's argument that, if MISO TOs' cost of equity increases in the future and long-term investors in utility stocks begin to perceive more favorable risk-adjusted investment alternatives, MISO TOs are free to file for a return that will allow them to retain the confidence of investors willing to commit funds to ensure their creditworthiness and long-term financial integrity. Although Paragraph 50 assumes that the DCF inputs have been distorted by economic abnormalities, Trial Staff states that, in this instance, the only DCF input at issue, current dividend yield, has fallen in line with declining interest rates as a result of market forces, consistent with an economic relationship that has been long accepted by the Commission. Trial Staff explains that the decline in interest rates, to a greater or lesser extent driven by policies of the Federal Reserve, as well as other market forces, has resulted in a decline in dividend yield and in the cost of equity capital. Trial Staff further explains that the current level of dividend yield on utility stocks simply reflects the decline in the cost of equity, rather than some amorphous and unexplained distortion in measuring it. Trial Staff concludes that, given the absence of credible evidence that either of the DCF inputs, current dividend yield or earnings growth has been distorted by purportedly anomalous capital market conditions, placement of MISO TOs' base ROE at the midpoint of the DCF zone of reasonableness automatically ensures that the capital attraction standards of *Hope* and *Bluefield* will be met.[182]

80. Trial Staff avers that while the Federal Reserve's Quantitative Easing programs undoubtedly helped the Treasury Department finance the large federal deficits following the 2008 financial crisis and necessarily had some impact on lowering yields on Treasury debt,[183] other actors in the financial community besides the Federal Reserve, both public and private, were acquiring Treasury debt at historically low yields. Trial Staff asserts that after the Federal Reserve's third round of Quantitative Easing program ended in October 2014, the market interest rate on long-term Treasury debt continued to decline.[184] Trial Staff asserts that this fact implies that the participation of private

---

[181] *Id.* at 40 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 204-205).

[182] *Id.* at 41.

[183] *Id.* at 25 (citing Exh. S-1 at 107:20-108:10).

[184] *Id.* (citing Exh. S-7).

investors contributed meaningfully to interest rates on Treasury debt, and that resulting rates were less the result of Federal Reserve intervention than the product of private capital market activity responding to prevailing market conditions.[185]

81. Trial Staff notes that, on several occasions in his Initial Decision, the Presiding Judge dismissed assertions concerning other structural reasons for the low interest rates during the DCF study period and appeared to adopt the MISO TOs' position that intervention by the Federal Reserve was the sole or central cause.[186] For example, Trial Staff states that the Presiding Judge rejected arguments by Trial Staff and other participants that the current level of long-term interest rates and their potential future trajectory is due in part to investors' expectations concerning future inflation.[187] Furthermore, Trial Staff contends that the Initial Decision presents a distorted analysis of the array of relevant economic forces impacting the capital markets during the DCF study period.

82. Trial Staff states that, while the Presiding Judge acknowledges present circumstances, he does not concede that low interest rates, low dividend yields, and high equity prices reflect low equity costs.[188] Trial Staff asserts that this is conceptually incorrect and contrary to the Commission's accepted position and may have led the Presiding Judge to make subsequent findings that are also inconsistent with the factual record and accepted economic logic.

83. Trial Staff asserts that the record lacks evidence that long-term investors in utility stocks, with at least a partial focus on the anticipated return offered by a potentially increasing stream of future dividend payouts, are deserting utility stocks. Trial Staff states that the Presiding Judge's speculation that the "Total Returns"[189] provided by an investment in utility stocks may currently be unsatisfactory to long-term investors whose participation is necessary to maintain their financial integrity and creditworthiness[190] is

---

[185] *Id.* at 25-26.

[186] *Id.* at 27 (citing, *e.g.*, Initial Decision, 153 FERC ¶ 63,027 at PP 170-180, 221-223).

[187] *Id.* at 27 (citing, *e.g.*, Initial Decision, 153 FERC ¶ 63,027 at PP 169, 189 n.249).

[188] *Id.* at 34 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 137, 215, 216).

[189] *Id.* at 37.

[190] *Id.* at 37-38 (citing Initial Decision, 153 FERC ¶ 63,027 at P 218).

contradicted by long-term investors' continued investment in those stocks. Trial Staff states that, while investment by "hot money" investors in utility stocks may have contributed to an increase in utility stock prices and reduced total returns provided by them by reducing current dividend yield, this merely reflects a decline in the overall market cost of debt and equity capital in an efficient market.

84. Trial Staff further argues that the Presiding Judge accepted MISO TOs' position that interest rates are likely to rise significantly in the future while virtually ignoring other evidence that this is unlikely to happen. Trial Staff points to the fact that Dr. Avera proffers a claim almost identical to that which he has been making since his testimony in the Opinion No. 531 proceeding,[191] that the existence of "widespread expectations in the investment community are for interest rates to rise significantly as the Federal Reserve moves to normalize its monetary policies and the economy moves toward a more normal pattern of growth."[192] Trial Staff counters that interest rates have gone down rather than up since that time, as shown in Exhibit No. S-7.[193] Finally, Trial Staff offers the example that, while the Presiding Judge gave decisional weight to predictions of increases in interest rates by sources cited by Dr. Avera, he dismissed the views of other observers on this same issue.[194] According to Trial Staff, under these circumstances, there is no basis to refer to alternative methodologies to inform placement of MISO TOs' cost of equity within the DCF zone.

85. Iowa Group states that MISO TOs failed to sustain their burden of proving that alleged anomalous market conditions had skewed the DCF inputs.[195] Iowa Group argues that the Presiding Judge erred by reinterpreting *Hope* and *Bluefield* to classify investors on the basis of their investment intent or motivation. Iowa Group asserts that Ms. Lapson did not quantify any impact that "hot money" investors might have on the price or prices of any particular proxy group, observing that the retreat of "hot money" would drive proxy group prices down and dividend yields up.[196]

---

[191] *Id.* at 30 (citing Exh. NET-300 at 12-14; Tr. 616:17-618:11).

[192] *Id.* at 30 (citing Exh. MTO-23 at 103:15-17).

[193] *Id.* at 30.

[194] *Id.* at 30-31 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 189, 223).

[195] Iowa Group Brief on Exceptions at 11.

[196] *Id.* at 13 (citing Initial Decision, 153 FERC ¶ 63,027 at P 210).

86. Iowa Group also asserts that the evidentiary record does not establish that a utility's financial stability and growth is irrelevant (or of far less interest) to short-term investors. It further states that *Hope* and *Bluefield* require that a utility's ROE be: (1) fair to *all* shareholders, regardless of the weight a shareholder places on the growth or yield of a particular stock; and (2) fair to consumers as well, meaning protecting them from exorbitant rates[197] or as Congress opined when it enacted the FPA, from deficient markets.[198] Iowa Group states that if the Presiding Judge's classification of shareholders is correct, the possibility of overcompensating investors rises significantly.

87. Iowa Group argues that the Presiding Judge also erred in finding that (1) short-term investors are supporting the proxy group utilities' stock prices, inflating share values and depressing dividend yields, and that this "fact" provides "no assurances that these utilities' Total Returns are sufficient to satisfy the requirements of the long-term investor,"[199] as well as (2) low interest rates set by the Federal Reserve Bank had distorted DCF calculations by driving down the yields of Baa Bonds and thereby skewing the 100-basis point screen.[200]

88. Additionally, Iowa Group states that the Presiding Judge excluded Edison International, FirstEnergy, and Entergy from the proxy group because their estimated ROEs (4.38 percent, 5.01 percent, and 5.36 percent, respectfully) either fell below the average Baa Bond yield (4.65 percent) or exceeded it by less than 100 basis-points. Iowa Group asserts that if, as the Presiding Judge found, short-term investors purchase utility shares only to obtain their dividend yield, it follows that such investors would purchase FirstEnergy shares because the higher adjusted dividend yield they would receive from such purchases (3.99 percent) would equal, or exceed, the yield they would receive from two of the 39 proxy group companies. Iowa Group further asserts that the same would be true for Entergy, which, according to Appendix A, has an adjusted dividend yield of 4.23 percent. Iowa Group offers that if the Presiding Judge is correct, then short-term

---

[197] *Id.* at 15 (citing *American Pub. Power Assoc. v FPC*, 522 F. 2d 142, 147 (D.C. Cir. 1975) (Bazelon, J. concurring) and *Washington Gas Light Co. v. Baker*, 188 F. 2d 11, 15 (D.C. Cir. 1950) (referencing U. S. Supreme Court cases dating back to 1890)).

[198] *Id.* at 15 (citing *Morgan Stanley Capital Group, Inc. v. Pub. Util. District No. 1*, 554 U.S. 527, 564 (2008) (Ginsburg, J. concurring)).

[199] *Id.* at 15-16 (citing Initial Decision, 153 FERC ¶ 63,027 at P 210).

[200] *Id.* at 18-19 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 155-157).

investors would be purchasing Entergy shares since that yield exceeds the yields they would earn on the shares of 29 out of the 37 final proxy group companies.[201]

89. Iowa Group argues that this evidence indicates that either the Presiding Judge is correct in finding all estimated ROEs below 5.65 percent (to use Dr. Avera's word) illogical and FirstEnergy and Entergy must be excluded from the final proxy group *or* it is correct in finding that short-term investors are purchasing equity only for dividend yield and FirstEnergy and Entergy should be included in the final proxy group. Iowa Group states that these findings are mutually exclusive.

90. Iowa Group states that the Presiding Judge erred when it found that low interest rates set by the Federal Reserve distorted DCF calculations by driving down the yields of Baa Bonds and thereby skewing the 100-basis point screen.[202] Iowa Group argues that the 257 basis point fluctuation in average Baa bond yields over the six and a half years after 2008 that the Presiding Judge highlighted in the Initial Decision does not prove that the DCF's low-end outlier screen was distorted.[203] In fact, Iowa Group points out that the magnitude of this fluctuation pales in comparison to other six-year periods shown on the same exhibit.[204] Iowa Group avers that the fact that a small variance in Baa bond yields coincided with Federal Reserve Bank's implementation of an economic stabilization and stimulus policy is hardly the foundation for finding a distortion in DCF calculations. Moreover, Iowa Group states that even if the "low-end outlier" screen were increased to its 2008 level of 8.22 percent and applied to the DCF results shown in the Initial Decision's Appendix B, the resulting Base ROE would be lower than that set by the Initial Decision. Iowa Group also states that this screen produces a zone of reasonableness that extends from an estimated return of 8.32 percent for SCANA Corporation to the 11.35 percent estimated return for TECO. Iowa Group asserts that, having corrected the effect of the alleged anomalous market conditions on the DCF inputs by raising the bottom of the zone, MISO TOs' new base ROE would not exceed the midpoint, which is 9.835 percent.[205]

[201] *Id.* at 17.

[202] *Id.* at 18-19 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 155-157).

[203] *Id.* at 19 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 157).

[204] *Id.* (citing Exh. S-5 at 2).

[205] *Id.* at 19-20.

91. Iowa Group asserts that the Commission has adjusted a base ROE up or down from the midpoint when there is substantial evidence to do so.[206] Iowa Group states that, given the lack of evidence to adjust a base ROE here, three options are available: (1) acknowledge the absence of evidence and set the base ROE at the midpoint; (2) re-open the record to allow the parties to submit proof as the extent of the effect; or, (3) consider Opinion No. 531's placement of the base ROE to be a default placement unless the record supports another quantification method. Iowa Group states that the Presiding Judge chose the last option, which constitutes clear error.[207] Iowa Group asserts that under the Administrative Procedure Act, the Presiding Judge was required to "articulate a rational connection between the facts found and the choices made."[208] Iowa Group further asserts that the Presiding Judge's punting of the quantification issue by defaulting to Opinion No. 531's Base ROE placement does not establish such a connection.

92. Iowa Group asserts that the Presiding Judge's utilization of a default quantification is particularly inappropriate in this case because it assumes, without proof, that the alleged anomalous market conditions affected the DCF inputs for each of the proxy companies to exactly the same extent. Iowa states that the Commission's practice of setting RTO-wide Base ROEs at the DCF midpoint rests on the assumption (upheld by the courts) that when setting the Base ROE for a diverse set of transmission companies, the midpoint of the proxy group's DCF zone of reasonableness is reasonably representative of the range of risks experienced by the RTO members. Iowa further explains that in other words, the midpoint, by taking into account the highest and lowest results, assures that the Base ROE accurately reflects the risk experienced by companies analogous to the RTO members.[209] Iowa Group states that there is no such assurance in

---

[206] *Id.* at 20-21 (citing *S. Cal. Edison Co.*, 92 FERC ¶ 61,070, at 61,266 (2000); *Consumers Energy Co.*, 85 FERC ¶ 61,100, at 61,363-61,364 (1998). Iowa Group explains that both of these cases involved adjusting the utility's ROE above the DCF midpoint because, based upon the record evidence, the Commission found that the utility's risk profile differed from that of the proxy group. In the case at hand, MISO TOs did not present any evidence to support a finding that they were riskier than the ID's proxy group. Iowa Group Brief on Exceptions at n.60.

[207] *Id.* at 21.

[208] *Id.* at 22 (citing *Pub. Serv. Comm'n v. Fed. Energy Reg. Comm'n*, 397 F.3d 1004, 1008 (D.C. Cir. 2005)).

[209] *Id.* (citing *S. Cal. Edison v. Fed. Energy Reg. Comm'n*, 717 F.3d 177, 183 (D.C. Cir. 2013); *City of Charlottesville v. Fed. Energy Reg. Comm'n*, 661 F.2d 945,

(continued...)

this case. In fact, Iowa Group avers that there is no evidence in this case as to whether the Presiding Judge's 103 basis point upward adjustment is reasonably representative of the effect of the economic anomalies on MISO TOs' Base ROE. Iowa Group concludes that without such evidence, the Presiding Judge's placement of the Base ROE at the midpoint of the zone of reasonableness's upper quartile does not constitute reasoned decision-making.[210]

93. Iowa Group asserts that the Presiding Judge's upward adjustment of the DCF zone of reasonableness's midpoint constitutes nothing more than an adjustment to normalize the DCF results so that they reflect the results that would be produced under "normal" financial market conditions. However, according to Iowa Group, the Commission has held that it does not make such adjustments as evidenced by its findings in *Portland Natural Gas Transmission System*.[211] Iowa Group states that the Commission instead explicitly rejected the argument that DCF data from the immediately preceding time period would be more appropriate and found that the cost of capital for the pipeline was representative of the time period in issue, measured by the DCF methodology without special consideration to the underlying turmoil in the financial markets. Iowa Group further states that when the same pipeline underwent another rate review in an immediately subsequent time period, the DCF results reflected those changes.[212] Iowa Group asserts that it is therefore not impermissible or problematic for the Commission to measure the cost of capital on the basis of prevailing capital markets, whether they be favorable or unfavorable to equity investors on the one hand, or consumers on the other. Iowa Group avers that the Commission should not make a practice of "normalizing" Base ROE allowances to take account of unusual or idiosyncratic conditions in the financial markets, especially here, where, as Ms. Lapson testified, the process of normalizing markets could last up to 30 years and the exact extent of alleged anomalies on the DCF model's inputs for the proxy companies is completely unknown.[213]

950-51 (D.C. Cir. 1981)).

[210] *Id.* at 22.

[211] *Id.* at 23-24 (citing *Portland Nat. Gas Transmission System,* Opinion No. 510-A, 142 FERC ¶ 61,198, at PP 219-220 (2013), *aff'g in relevant part*, Opinion No. 510, 134 FERC ¶ 61,129 (2011)).

[212] *Id.* at 24 (citing *see* Opinion No. 510, 134 FERC ¶ 61,129 at P 225; *Portland Nat. Gas Transmission System*, Opinion No. 524, 142 FERC ¶ 61,197, at PP 6, 290, and 323 (2013)).

[213] *Id.* at 24.

94. Iowa Group asserts that the expansive character of the generalizations relied upon in the Initial Decision to justify its upward adjustment of the DCF zone of reasonableness's midpoint, combined with their amorphous evidentiary connections to the DCF inputs and the lack of data quantifying the extent of the alleged economic anomalies impacts on those inputs, provide fertile ground for future claims for similar adjustments. Iowa Group argues that avoiding this result requires the Commission to reject the Presiding Judge's upward adjustment of the Base ROE on the ground that it does not withstand the rigorous scrutiny emphasized by Commissioner Honorable in Opinion No. 531-B.[214]

95. Joint Customer Intervenors assert that the current capital market conditions are neither "unprecedented" nor "unsustainable," and do not deviate from what is normal, but are instead evidence of a new and consistent normal.[215] Joint Customer Intervenors state that the capital market conditions cited in Opinion No. 531 have lasted at minimum four years and therefore have been shown to be sustainable. Joint Customer Intervenors refer to Mr. Solomon's analysis, which demonstrates that "[t]he consistency and persistence of the levels of capital costs over that . . . period demonstrate that current bond yields cannot be considered aberrational, but rather reflect a new and consistent normal."[216] Joint Customer Intervenors state that the current bond yields appear to be "part of a long-term decline in yields that began in the early 1980s."[217] Joint Customer Intervenors assert that former Federal Reserve Board Chairman, Dr. Benjamin Bernanke, has stated that "[l]ow interest rates are not a short-term aberration, but part of a long-term trend" and that "ten-year government bond yields in the United States were relatively low in the 1960s, rose to a peak above 15 percent in 1981, and have been declining ever since."[218]

96. Joint Customer Intervenors contend that the Presiding Judge's focus on the actions of the Federal Reserve, rather than on the actual market conditions such as the relatively low level of interest rates and inflation, appears to have contributed to the determination

[214] *Id.* at 24-25.

[215] Joint Customer Intervenors Brief on Exceptions at 17-18 (citing Exh. JCI-1 at 27:16-19).

[216] *Id.* at 18 (citing Exh. JCI-1 at 27:16-19).

[217] *Id.* at 19 (citing Exh. JCI-4 at 27:5-7).

[218] *Id.* at 20-21 (citing Exh. JCI-6 at 1).

that anomalous market conditions existed.[219] Joint Customer Intervenors state that the Federal Reserve acted to stimulate the economy after the Great Recession, which Joint Customer Intervenors argue would tend to increase economic activity, inflation, and the opportunity cost of capital.[220] Joint Customer Intervenors assert that the Presiding Judge's reliance on the actions of the Federal Reserve as the cause of the alleged anomalous market conditions is unfounded because, without the actions of the Federal Reserve, inflation and the cost of capital could have been lower.[221]

97. According to Joint Customer Intervenors, Mr. Solomon demonstrated that, despite MISO TOs' claim that Federal Reserve bond purchases had made bond investments unavailable to investors interested primarily in yield, federal debt as a percentage of annual GDP has doubled since 2008.[222] Joint Customer Intervenors state that the Presiding Judge dismissed Mr. Solomon's exhibit because the questions raised therein were highly technical and there was a lack of expert testimony.

98. Joint Customer Intervenors also state that the Presiding Judge erred by holding that *Hope* and *Bluefield* require the Commission to distinguish between short- or long-term investors, and by finding that the evidence demonstrates that MISO TOs are only attracting short-term investors.[223] According to Joint Customer Intervenors, the Presiding Judge determined that an ROE can be considered too low if the capital made available to the company comes from the wrong type of investors. Joint Customer Intervenors assert, however, that a short-term investor selling its stock has to accept a price based on the expected long-term cash flow to be derived from the stock.[224]

99. Joint Customer Intervenors also point out that "[r]ates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as

---

[219] *Id.* at 23.

[220] *Id.* at 24 (citing Exh. JCA-1 at 6:9-15, 7:10-12; Exh. JCA-11 at 24:10-12.).

[221] *Id.* at 24.

[222] *Id.* at 25 (citing Exh. JCI-7).

[223] *Id.* at 26.

[224] *Id.* at 27 (citing *Williston Basin Interstate Pipeline Co.*, 81 FERC ¶ 61,033, at P 61,175 (1997) (*Williston Basin*) ("even a short-term investor would be concerned about long-term growth . . . ."]).

invalid."[225] Joint Customer Intervenors state that the Initial Decision appeared to take a different view by acknowledging that "the cost to electric utilities of raising capital by issuing stock is also low" but nevertheless holding that "this does not mean that the [cost of equity] is low."[226] According to Joint Customer Intervenors, the Presiding Judge thereby found that an ROE set at the DCF midpoint would enable MISO TOs to raise capital, yet would be insufficient to attract long-term investors and thus would fail to comply with the Initial Decision's interpretation of *Hope* and *Bluefield*. Joint Customer Intervenors contend that the Presiding Judge failed to support the theory that the cost of equity is higher than the cost of raising capital, and assert that this theory is contrary to existing precedent.[227]

100. Joint Customer Intervenors also argue that the Presiding Judge erred by concluding that MISO TOs would not attract a sufficient number of long-term investors if the ROE were set at the midpoint of the DCF range of reasonableness. According to Joint Customer Intervenors, the Initial Decision suggested that a period of six years and eight months may qualify as short-term.[228] Joint Customer Intervenors argue that, if six years and eight months qualifies as short-term, the Presiding Judge effectively held that the midpoint of the DCF can only be relied upon when evidence demonstrates that most investors plan to hold their securities for at least seven years. Joint Customer Intervenors assert, however, that no court or regulatory agency has ever required such a showing.[229]

101. According to Joint Customer Intervenors, the Presiding Judge assumed that the supposed prevalence of short-term investors among utility stockholders is significant because short-term investors are likely to sell their stock as soon as the allegedly anomalous conditions change. Joint Customer Intervenors state that this assumption relied on Ms. Lapson's belief that it is anomalous for investors to buy and hold yield-producing securities when they expect interest rates to rise.[230] Joint Customer

[225] *Id.* at 27 (citing *Hope*, 320 U.S. 605).

[226] *Id.* at 27-28 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 215-216).

[227] *Id.* at 28 (citing *Boston Edison Co. v. FERC*, 885 F.2d 962, 965 (1st Cir. 1989) (holding that the DCF asks "what is the minimum amount that one must pay new investors . . . to offer the utility the money that it needs for investment")).

[228] *Id.* (citing Initial Decision, 153 FERC ¶ 63,027 at P 177).

[229] *Id.* at 29.

[230] *Id.* at 35 (citing Initial Decision, 153 FERC ¶ 63,027 at P 146).

Intervenors argue, however, that the forecasts cited in the Presiding Judge predict interest rates to rise by 2019 and that it is hardly anomalous for investors to expect interest rates and other capital market parameters to change over the ensuing several years. Furthermore,
Joint Customer Intervenors note that the Presiding Judge stated that "the Federal Reserve's calibration of its increase in the federal-funds target rate . . . may delay the rate impact of normalization, but will not prevent the suddenness of that impact once short-term rates start to provide acceptable yield."[231] Joint Customer Intervenors argue that, even if the Presiding Judge is correct and a sudden selloff of utility stocks by short-term investors leaves MISO TOs with difficulty raising capital, MISO TOs have the right under FPA section 205 to file for increased rates and to put those increased rates into effect after 60 days. Joint Customer Intervenors contend that the Presiding Judge would effectively require customers to pay excessive rates for years to avoid the possibility that MISO TOs might collect insufficient rates for 60 days. Joint Customer Intervenors, therefore, assert that the Initial Decision thus failed to engage in "a balancing of the investor and the consumer interests."[232]

102. Joint Customer Intervenors also argue that the Presiding Judge erred in finding that the reliability of the DCF analysis in this proceeding should be called into question.[233] Joint Customer Intervenors assert that the Commission's two-step DCF methodology, when properly implemented, correctly measures the market cost of capital. Joint Customer Intervenors explain that the Commission's DCF methodology is based on three major components: the dividend, the price of common stock, and the expected dividend growth rate.[234] Joint Customer Intervenors state that the dividend is published by the company and the price of common stock is determined in the competitive marketplace, while growth rate forecasts are developed and published by independent entities that generally are relied on by investors in forming their future outlook. Joint Customer Intervenors assert that, as the DCF methodology is forward-looking and based on the expectations of investors, the DCF results reflect the reality of the capital markets and the actual market cost of equity capital.[235]

---

[231] *Id.* at 35-37 (citing Initial Decision, 153 FERC ¶ 63,027 at P 199).

[232] *Id.* at 29-30 (citing *Hope*, 320 U.S. 345).

[233] *Id.* at 21 (citing Initial Decision, 153 FERC ¶ 63,027 at P 228).

[234] *Id.* at 21-22 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 15).

[235] *Id.* at 22-23.

103. According to Joint Customer Intervenors, the Presiding Judge relied heavily on the finding of anomalous capital market conditions in Opinion No. 531, yet failed to recognize that the record established in the instant proceeding differs from that before the Commission in Opinion No. 531 and compels the conclusion that capital market conditions cannot be considered anomalous in the relevant period.[236] Joint Customer Intervenors assert that the Presiding Judge considered arguments that were not found in Opinion No. 531 in support of MISO TOs' contention that conditions were anomalous, but dismissed arguments that conditions were not anomalous because the Commission had not accepted such arguments in Opinion No. 531.[237]

104. Joint Customer Intervenors contend that the record in the instant proceeding includes the following factors that, in contrast to the finding of anomalous market conditions in Opinion No. 531, indicate that economic conditions have not been aberrational: (1) the six-month average ten-year U.S. Treasury bond yield was above two percent by 28 basis points; (2) the unemployment rate dropped substantially to below six percent; (3) the economy expanded and the stock market was strong; (4) the Federal Reserve had substantially wound down its Quantitative Easing initiative; and (5) inflation remained below the Federal Reserve's Open Market Committee's two percent target level.[238] Joint Customer Intervenors argue that the Presiding Judge did not closely examine these conditions or explicitly reject the evidence that the market conditions do not warrant an upper-midpoint ROE for MISO TOs and thus erred in finding that market conditions were anomalous.[239]

105. Joint Customer Intervenors argue that the evidence presented in the hearing failed to demonstrate a correlation between the ROE and the level of transmission investment. They state that MISO TOs' witness, Mr. Kramer, was not able to say whether a base ROE greater than 12.38 percent would have resulted in the construction of more new projects.[240] Joint Customer Intervenors also claim that Mr. Kramer was unable to provide evidence of whether a lower base ROE would have resulted in the same level of benefits.[241] Joint Customer Intervenors also argue that the Presiding Judge relies upon

[236] *Id.* at 15-16 (citing Opinion No. 531, 147 FERC ¶ 61,234 at PP 115, 116, 119).

[237] *Id.* at 16 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 205).

[238] *Id.* at 17 (citing Exh. JCI-1 at 26:12-23).

[239] *Id.*

[240] *Id.* at 52-53 (citing Exh. JCI-14 at 1).

[241] *Id.* at 53 (citing Exh. JCI-13 at 1).

the statements of MISO TOs' witness, Ms. Lapson, asserting that an ROE reduction would result in a reduction in earnings and cash flow, and that credit ratings might be affected.[242] Joint Customer Intervenors claim, however, that no party provided evidence to suggest that the base ROE that Joint Customer Intervenors argue for would impair transmission investment in MISO.[243]

106. Joint Customer Intervenors also argue that the capital market conditions during the study period in the instant proceeding were similar to those addressed in the May 12, 2015 Entergy Initial Decision,[244] in which the Presiding Judge found that capital market conditions were not anomalous. Therefore, Joint Customer Intervenors argue that the Presiding Judge erred in finding such conditions were anomalous here.[245]

107. OMS states that evidence submitted by Trial Staff showing historical bond yields going back to the year 1919 leads to the conclusion that the low bond yields seen during the study period in this docket are not unprecedented.[246] OMS also states that the Presiding Judge essentially found that capital market conditions are "anomalous" because they are unsustainable, and they are unsustainable because either interest rates will go up or investors will stop expecting them to go up. OMS states that the simple fact is that market conditions change over time because the market forces that shape those conditions change over time. Furthermore, OMS contends that whether or not investors perceive the Federal Reserve's accommodative monetary policy as temporary is beside the point because, it can credibly be argued, *all* market forces are temporary.[247] OMS argues that what actually matters is whether investors expect that the eventual ending of the Federal Reserve's current program of accommodative actions will significantly impact their investments, such as by causing interest rates and bond yields to spike. OMS contends that the answer is far less certain than the Initial Decision suggests.

---

[242] *Id.* at 54 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 463-470).

[243] *Id.*

[244] *Entergy Ark., Inc.*, 151 FERC ¶ 63,008, at P 89 (2015) (Entergy Initial Decision).

[245] Joint Customer Intervenors Brief on Exceptions at 24-25.

[246] OMS Brief on Exceptions at 13-14 (citing Exh. S-1 at 12).

[247] *Id.* at 16 (emphasis supplied).

108. OMS also states that the record evidence casts considerable doubt on the extent to which Federal Reserve policies actually affect the inputs to a DCF study. For example, OMS contends that the record includes an article written by Dr. Bernanke questioning the Federal Reserve's ability to affect interest rates over the long-term, and stated that real interest rates are determined by a broad array of economic factors (including prospects of economic growth), not solely by Federal Reserve actions.[248] In addition, OMS states that the Presiding Judge agrees with MISO TOs' contention that Federal Reserve policy decreased yields on long-term U.S. Treasury bonds by increasing the demand for (and prices of) those securities, but it ignores the *supply* side of that equation.[249] OMS states that overlapping in time with Quantitative Easing, but swamping it in magnitude, large Federal deficits were being financed by the issuance of new federal debt securities, to the extent that Federal debt as a share of Gross Domestic Product more than doubled after 2008.[250] OMS argues therefore that even if Quantitative Easing bond purchases exerted a downward pressure on bond yields (by pulling down the supply of U.S. Treasury bonds, driving up their price and pushing down yields), new Federal bond issuances to finance the growing deficit had the opposite effect; by adding to the supply of Federal debt securities, prices were pushed down and yields were driven up.

109. OMS states that the Presiding Judge found that, as a result of falling interest rates and dividend yields, the cost to electric utilities of raising capital by issuing stock is low.[251] OMS states, however, that the Presiding Judge erred by rejecting the conclusion that logically follows from the finding – namely, that the costs of common equity for utilities is also low. OMS argues that the Presiding Judge's findings in this regard rely on the premise that the cost of equity must satisfy the total return requirements of a long-term investor to satisfy *Hope* and *Bluefield*.[252] OMS states that none of the testimonies prepared by MISO TOs' expert witnesses' distinguish between the required returns of long-term versus short-term investors to satisfy the standards in *Hope* and *Bluefield*. Rather, OMS states that the distinction was first included in the record during the hearing as part of the Presiding Judge's clarification question to Ms. Lapson. OMS contends that Complainants and supporting intervenors had no opportunity to include expert

---

[248] *Id.* at 23 (citing Exh. JCI-6 at 2).

[249] *Id.* at 24 (citing Initial Decision, 153 FERC ¶ 63,027 at P 123 (emphasis supplied)).

[250] *Id.* (citing Exh. JCI-7 at 84, figure 1).

[251] *Id.* at 25 (citing Initial Decision at P 215).

[252] *Id.* at 25-26 (citing Initial Decision, 153 FERC ¶ 63,027 at P 210).

testimony in the record to address this new distinction and whether it is at all relevant to determining the cost of equity of MISO TOs. OMS states that Complainants and supporting intervenors could not have anticipated such issues being raised during the hearing because: (1) the DCF does not distinguish between "short-term" and "long-term" investors; and (2) there is no Commission precedent discussing the proposition that there is a difference between the results of the DCF study and the true cost of equity.

110. OMS states that the finding that the DCF analysis does not reflect the true cost of equity because it does not satisfy the requirements of the long-term investors was developed by the Presiding Judge who, according to OMS, appears to be uncertain himself about the validity of this theory.[253] OMS states that the Commission should not affirm rulings that rely on such equivocal findings. OMS states that there is no credible evidence in the record showing that investors no longer care about dividend growth and continue to invest in the utility stock just for the yield. Moreover, OMS contends that if the Presiding Judge's theory is credited, then the Presiding Judge contradicted himself in discarding as illogical two low-end results that exceeded the study-period Baa utility bond yield of 4.65 percent, but did so by less than 100 basis points.[254] OMS states that the basis of the standard 100 basis point screen is a finding that investors in utility stocks require appreciably more yield than utility bonds provide.[255]

111. OMS states that investor behavior belies any expectation of sharply increased interest rates. OMS states that MISO TOs' case is grounded on the proposition that investors are (and, during the study period, were) expecting an impending end to the capital market conditions that have prevailed for the past several years, once the Federal Reserve begins to normalize its post-recession monetary policies.[256] OMS states that

---

[253] *Id.* at 27 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 216 (the total returns of proxy companies "are not necessarily" equivalent to their cost of equity), 218 (expectations of dividend growth "may" not be guiding investment decisions; investors "may" be purchasing stock only for the current yield; the proxy group stock prices "may" not reflect long-term investors satisfaction)).

[254] *Id.* at 27-28 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 65, 158).

[255] *Id.* at 28 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 122 ("The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt.")).

[256] *Id.* at 20 (citing Initial Decision, 153 FERC ¶ 63,027 at P 222).

MISO TOs also contend that investors expect a sharp rise in interest rates and bond yields – an expectation that renders the current conditions “anomalous.” OMS argues that, while the Initial Decision accepts both premises of MISO TOs’ case, there is a significant flaw in MISO TOs’ theory. OMS contends that a fundamental assumption of the DCF method is that investors are rational actors who manifest their knowledge and expectation about the market through the prices they are willing to pay for stock. OMS states that if investors in utility stocks are expecting an imminent jump in interest rates due to Federal Reserve policy normalization, their rational response would be for them to sell those stocks before the increases in interest rates begin. If the expectation were sufficiently widespread and enough investors pursue the path of rational self-interest, OMS contends that utility stock prices would fall as shares are sold into the market, which would cause the dividend yields on those stocks to increase. But, OMS argues that the record evidence shows that simply has not happened. According to OMS, that yields on utility stocks have not increased implies that investors have elected not to sell their shares, a decision that can only mean that investors expect that the normalization of Federal Reserve monetary policy will be gradual and have little to no adverse impacts on the value of their holdings.[257]

112. OMS states that the Presiding Judge’s finding that, during the study period, “many investors have expected that the Federal Reserve will normalize current market-capital conditions, and that interest rates will rise significantly over the next few years,” is contradicted by evidence in the record.[258] OMS contends that the record demonstrates that, since the Federal Reserve ended its Quantitative Easing Program in October 2014, bond yields and interest rates changed very little.[259] OMS states that, contrary to the Presiding Judge’s findings, the record shows that during the study period there was no clear consensus within the investment community as to what specific actions the normalization of Federal Reserve policy would entail, or what impact those actions might have on interest rates and bond yields. OMS states that, prior to or within the study period, the Federal Reserve reassured the investment community that any change in its accommodative monetary policy would not be drastic. OMS states the January 2015 minutes to the Federal Open Market Committee, cited by Ms. Lapson and included in the record, include a resolution to maintain the Federal Reserve policy of reinvesting principal payments from its holdings of agency debt and agency mortgage backed securities because maintaining a sizable level of long-term securities “should help

[257] *Id.* at 19-20.

[258] *Id.* at 16-17 (citing Initial Decision, 153 FERC ¶ 63,027 at P 222).

[259] *Id.* at 17 (citing Exh. S-1 at 63:21-22; Exh. JCI-1 at 27:9-14).

maintain accommodative financial conditions."[260] OMS contends that, although the Presiding Judge interpreted the Federal Open Market Committee minutes to support a finding that investors expect interest rates to rise because the minutes indicate that "normalization" could start at any time, the minutes can just as easily be understood to say that, even if investors believed that a change in the Federal Reserve's accommodative monetary policies was a certainty and that it would lead to higher interest rates, investors also knew that any such policy changes (1) could take some time to implement, and (2) would likely be carefully measured (not dramatic or sudden) because the Federal Reserve also was charged with pursuing a set of important economic objectives that were tied to promoting recovery from the recent recession.

c. <u>Brief Opposing Exceptions</u>

113. MISO TOs argue that the record demonstrates the existence of anomalous capital market conditions affecting DCF inputs and results and ask the Commission to affirm the Initial Decision's finding of anomalous market conditions.[261] MISO TOs point to the fact that the Federal Reserve holds "massive amounts" of U.S. Treasury bonds and mortgage-backed securities. They argue that these holdings cause bond prices to spike and yields to decline and suppress the short-term federal funds target rate, which leads fixed-income investors to seek yield in higher risk assets, such as electric utility stocks. MISO TOs state that these circumstances result in utility equity price increases and yield decreases.[262] In response to arguments that investors were aware of the Federal Reserve's policies during the relevant period and that the capital market has effectively settled into a "new normal" and cannot be considered anomalous, MISO TOs argue that these arguments conflate the duration of anomalies with the existence of anomalies.[263] Further, MISO TOs assert that the fact that these conditions have persisted longer than anticipated does not undercut the Presiding Judge's conclusion that investors expect the Federal Reserve to normalize and for interest rates to eventually rise.[264]

114. MISO TOs further argue that the DCF model is not infallible and dispute arguments that the DCF model accurately estimates the cost of equity capital irrespective

[260] *Id.* at 19-20 (citing Exh. S-10 at 20).

[261] MISO TOs Brief Opposing Exceptions at 7-8.

[262] *Id.* at 8.

[263] *Id.* at 9-10.

[264] *Id.* at 10.

of prevailing capital market conditions. MISO TOs argue that, in Opinion No. 531-B, the Commission stated that "all methods of estimating the cost of equity are susceptible to error when the assumptions underlying them are anomalous."[265] MISO TOs argue that accepting the opposing parties' contrary arguments here would disregard the Commission's explicit instruction in the Hearing Order that the participants' evidence and DCF analyses conform to Opinion No. 531.[266]

115. Moreover, MISO TOs argue that the Presiding Judge demonstrated how anomalies can undermine a model's ability to accurately estimate a utility's cost of equity and raised sufficient doubt about the DCF results' reliability to compel examination of alternative benchmarks.[267] In response to arguments that the Presiding Judge's analysis "failed to prove distortion of DCF inputs or quantify their impact," MISO TOs argue that Opinion Nos. 531 and 531-B require no such standard of proof, only sufficient evidence to question the reliability of the DCF midpoint.[268] MISO TOs further state that the Presiding Judge noted that the DCF midpoint will not be just and reasonable if it does not appropriately represent utilities' risks.[269]

116. MISO TOs further note that the Presiding Judge's analysis clearly links capital market conditions and the DCF model and explains that *Hope* and *Bluefield*'s dual standards can only "be rationally applied" in the context of long-term investment decisions, since short-term investors have less interest in a utility's financial integrity and creditworthiness.[270] MISO TOs contend that the Presiding Judge found credible testimony that capital market anomalies have caused investors to deploy capital in ways inconsistent with the objectives and assumptions underlying *Hope* and *Bluefield* and the DCF model. This evidence attested that historically low interest rates available from conventional long-term investments are driving investors to better yielding, riskier

[265] *Id.* at 11 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 50).

[266] *Id.* at 12 (citing Hearing Order, 149 FERC ¶ 61,049 at P 186).

[267] *Id.* at 12.

[268] *Id.* at 12.

[269] *Id.* at 13.

[270] *Id.* at 14.

alternatives, such as utility equities.[271] MISO TOs assert that, consequently, utilities' stock prices have risen and associated yields have declined.[272]

117. MISO TOs also respond to arguments that the Presiding Judge's analysis reflects an interpretation of *Hope* and *Bluefield* that is improperly applied to the DCF and arguments that the Presiding judge's findings cannot "be squared" with the correlation between the cost of debt and equity and the direction relationship between low interest rates, low dividend yields, high equity prices, and a low cost of equity.[273] MISO TOs argue that, in the context of establishing returns for regulated transmission owners, the concepts of capital attraction and financial integrity only have meaning in the long-term horizon as transmission assets take years to plan and construct and are often in service for decades.[274]

118. MISO TOs also take issue with attempts to marginalize the testimony of Ms. Lapson, arguing against the use of the midpoint DCF value by citing to opposing parties' own witnesses who acknowledge the effect of current capital market conditions on DCF inputs. MISO TOs argue, in short, that there is clear evidence that the Federal Reserve's historically unprecedented monetary policies have altered normal investment behavior.[275]

d. Commission Determination

119. We affirm the Presiding Judge's conclusions, though we do not adopt the totality of his reasoning, concerning anomalous capital market conditions. For the reasons discussed below, we conclude that the record in this proceeding demonstrates the presence of unusual capital market conditions, such that we have less confidence that the central tendency of the DCF zone of reasonableness (the midpoint in this case) accurately reflects the equity returns necessary to meet *Hope* and *Bluefield*.

120. As the Commission found in Opinion No. 531, the DCF methodology, like all cost of equity estimation methodologies, "may be affected by potentially unrepresentative

[271] *Id.* at 14.

[272] *Id.* at 14.

[273] *Id.* at 15 (citing Trial Staff Brief on Exceptions at 33-35).

[274] *Id.* at 16.

[275] *Id.* at 17.

financial inputs" as a result of unusual economic conditions.[276] As Roger A. Morin states in his treatise, *New Regulatory Finance*,[277] "by relying solely on the DCF model at a time when the fundamental assumptions underlying the DCF model are tenuous, a regulatory body greatly limits its flexibility and increases the risk of authorizing unreasonable rates of return." Therefore, it is reasonable, under those conditions, to consider the results of alternative methods for estimating the cost of equity when determining whether a mechanical reliance on the central tendency of the DCF-produced zone of reasonableness produces a just and reasonable ROE.[278] Our finding of anomalous market conditions does not, by itself, justify awarding an ROE above the central tendency of the DCF-produced zone of reasonableness. Rather, that finding supports a consideration of other cost of equity estimation methodologies in determining whether mechanically setting the ROE at the central tendency satisfies the capital attraction standards of *Hope* and *Bluefield*.

121. The record in this proceeding raises the same concerns regarding capital market conditions that the Commission identified in Opinion No. 531. Bond yields remained at historically low levels during the study period. For example, the yield on 10-year U.S. Treasury bonds, which the Commission noted in Opinion No. 531[279] was below two percent in that case and had not been below three percent since the 1950s, was at 2.07 percent[280] during the study period. Also, the yield on short-term U.S. Treasury bonds was historically low, ranging from zero to 0.25 percent.[281] Additionally, we note that, while the Federal Reserve has ended the Quantitative Easing program under which it was purchasing unprecedented levels of U.S. Treasury bonds and mortgage-backed securities,[282] the Federal Reserve continues to hold approximately \$4.25 trillion[283] of

---

[276] Opinion No. 531, 147 FERC ¶ 61,234 at P 41. *See also* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 50 ("all methods of estimating the cost of equity are susceptible to error when the assumptions underlying them are anomalous").

[277] *New Regulatory Finance* 28 (Public Utilities Reports, Inc. 2006).

[278] *See, e.g.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 145, *order on reh'g*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 50.

[279] Opinion No. 531, 147 FERC ¶ 61,234 at n.285.

[280] *See* Exh. S-5 at 8.

[281] *See* Exh. MTO-16 at 22-23.

[282] *See id.* at 17-20.

those bonds, a level only slightly below recent record highs, and is reinvesting the principal payments from those holdings to purchase approximately $16 billion of mortgage-backed securities per month and rolling over the U.S. Treasury bonds at auction.[284] This record evidence is indicative of the same type of unusual capital market conditions that the Commission found concerning in Opinion No. 531. Parties point out that certain capital market conditions have changed since Opinion No. 531, including the winding down of Quantitative Easing, the slight increase in U.S. Treasury bond yields, the lower unemployment rate, and strong stock market performance. Though the Commission noted certain economic conditions in Opinion No. 531, the principal argument was based on low interest rates and bond yields, conditions that persisted throughout the study period. Consequently, we find that capital market conditions are still anomalous as described above, and, therefore, we disagree with Iowa Group's assertion that there is not substantial evidence to justify a potential adjustment.

122. Because the evidence in this proceeding indicates that capital markets continue to reflect the type of unusual conditions that the Commission identified in Opinion No. 531, we remain concerned that a mechanical application of the DCF methodology would result in a return inconsistent with *Hope* and *Bluefield*.[285] We conclude that the fact that these conditions have persisted over the approximately two years since the end of the study period adopted in Opinion No. 531 does not, in and of itself, mean that these conditions are not anomalous. Ms. Lapson describes the model risk associated with the reliance on mechanical application of a model and discusses how it is necessary to test model outcomes against other investment benchmarks as a check.[286] As the Commission found in Opinion No. 531, under these circumstances, we have less confidence that the midpoint of the zone of reasonableness in this proceeding accurately reflects the equity

---

[283] *See id*. at 18, 23.

[284] *See* Exh. MTO-1 at 22.

[285] Opinion No. 531 states:

> There is 'model risk' associated with the excessive reliance or mechanical application of a model when the surrounding conditions are outside of the normal range. 'Model risk' is the risk that a theoretical model that is used to value real-world transactions fails to predict or represent the real phenomenon that is being modeled.

147 FERC ¶ 61,234 at n.6.

[286] *See* Exh. MTO-16 at 30-31.

returns necessary to meet the *Hope* and *Bluefield* capital attraction standards.[287] We therefore find it necessary and reasonable to consider additional record evidence, including evidence of alternative methodologies and state-commission approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the resulting midpoint.

123. Complainants and intervenors make a number of arguments against the Presiding Judge's determination that anomalous market conditions justify examining alternative methodologies and state-commission approved ROEs to assess whether the ROE should be placed in the upper half of the zone of reasonableness. Such arguments, discussed in more detail below, largely pertain to the Presiding Judge's reasoning, such as the distinction between short-term and long-term investors, reasoning that we do not adopt even though we reach the same conclusions. Additionally, because we base our conclusion on a different rationale than the Presiding Judge, we need not consider arguments regarding the Presiding Judge's consideration of evidence on which we do not rely.

124. Parties argue that the record does not support the Presiding Judge's finding that capital market conditions during the study period are anomalous, either generally or based on the Presiding Judge's definition of anomalous as "unprecedented and unsustainable." We do not adopt that definition so we do not need to consider those arguments here. As described above, evidence in the record regarding historically low interest rates and Treasury bond yields as well as the Federal Reserve's large and persistent intervention in markets for debt securities are sufficient to find that current capital market conditions are anomalous. Although the record indicates that there was a past period of similarly low interest rates, it occurred more than sixty years ago. Similarly, while Complainants provide evidence that interest rates have been trending downwards, the current levels may be so low as to cause irregularities in the outputs of the DCF. Despite such yields remaining low for several years, we find that they are anomalous and could distort the results of the DCF model.

125. Parties also argue that MISO TOs have not presented evidence that the actions of the Federal Reserve directly affected DCF methodology results. Specifically, Trial Staff argues that there is no credible evidence that any of the DCF inputs have been distorted by purportedly anomalous capital market conditions. As described above, we find that the relevant anomalous capital market conditions cited in Opinion No. 531 are still present in this proceeding. Moreover, because the analytical approach we use here, and which we used in Opinion No. 531, gives us confidence that the resulting ROE satisfies the requirements of *Hope* and *Bluefield*, a direct causal analysis linking specific capital

[287] Opinion No. 531, 147 FERC ¶ 61,234 at P 145.

market conditions to particular inputs or assumptions in the DCF model is not necessary. Consistent with Opinion No. 531, we find that the DCF methodology is subject to model risk of providing unreliable outputs in the presence of unusual capital market conditions.[288] The Commission has not required a mathematical demonstration of how each anomalous capital market condition specifically distorts the DCF analysis and it is uncertain whether such an analysis is even possible given the complexities of capital markets and how various phenomena could affect the DCF methodology results.[289] For that reason, in the presence of anomalous capital market conditions, the Commission examines other evidence, namely the results of alternative methodologies and state-commission approved ROEs to assess the reasonableness of the results of the DCF methodology. We find that the record contains sufficient evidence of anomalous capital market conditions.

126. We also disagree with arguments regarding the lack of effect of Federal Reserve's actions, including OMS' assertion that the effect on capital market conditions of increases in the Federal Reserve's holdings of U.S. Treasury bonds has been more than counteracted by large increases in federal debt outstanding during the same period. OMS has provided no evidence showing that increases in the amount of U.S. Treasury bonds directly counteract and nullify the effect of direct capital market interventions by the Federal Reserve.[290] Similarly, no party has shown that other global events or investor behavior caused the anomalous capital market conditions. Again, the fact remains that capital market conditions are anomalous, such that mechanical application of the DCF methodology could produce unreasonable results.

127. Parties raise numerous objections to the Presiding Judge's distinction between short-term and long-term investors in finding that the midpoint ROE produced by the application of the DCF methodology is insufficient. Because we do not adopt this

---

[288] Opinion No. 531, 147 FERC ¶ 61,234 at n.286.

[289] While we do not adopt the Presiding Judge's rationale concerning the specific causal link between the anomalous capital market conditions and the results of the DCF model, we acknowledge that the Presiding Judge's rationale might have merit and our determination here is without prejudice to that rationale. However, given the difficulty of establishing a causal relationship between complex capital market conditions and the results of any particular financial model, we are not persuaded that the record evidence in this proceeding is adequate to definitively conclude that the Presiding Judge's rationale explains how the current capital market conditions are impacting the DCF model.

[290] Further, we note that, even if more U.S. Treasury bonds are available, the low interest rates in the record are equally applicable to those bonds.

element of the Presiding Judge's reasoning, we need not respond to these objections. Instead, we find that where anomalous market conditions give us reason to have less confidence in DCF methodology outputs, it is reasonable to consider alternative methodologies and state-commission approved ROEs in determining a just and reasonable ROE. Our not adopting this reasoning also renders moot assertions regarding a contradiction between finding that short-term investors require lower returns and maintaining the 100-basis point low end screen in the DCF methodology.

128. Complainants are correct that the record does not contain evidence that economic conditions have "negatively impacted" the ability of MISO TOs to raise capital.[291] MISO TOs have been raising capital successfully with a 12.38 percent ROE, which we determine here is excessively high. However, MISO TOs bear no obligation to demonstrate difficulty raising capital in excess of the ROE adopted by the Initial Decision. Furthermore, there is record evidence that a decrease in ROE of that magnitude – a 309 basis point reduction from 12.38 percent to 9.29 percent –could undermine the ability of MISO TOs to attract capital for new investment in electric transmission.[292]

129. Parties also argue that, because the impending rise of interest rates will not happen suddenly or soon, the returns provided by the midpoint of the DCF analysis are sufficient. They also argue that rational investors would not invest in assets that are assumed to be likely to lose value soon. Such arguments are inapplicable to the rationale adopted in this order. Our reasoning, unlike the Presiding Judge's, does not rely on assessing investor expectations of the specific timing of potential interest rate increases that could affect utilities' future ability to raise capital. We do not find that the ROE needs to be sufficient for when interest rates increase. Similarly, we are not finding that investors are necessarily making investments without considering the potential effects on stock valuation of likely future interest rate increases. Rather, we find that current capital market conditions may cause the mechanical application of the DCF methodology to produce an ROE that does not meet the requirements of *Hope* and *Bluefield*.

---

[291] Complainants Brief on Exceptions at 33.

[292] Exh. MTO-1 at 7. For example, Ms. Lapson pointed out a June 11, 2013 Wolf Research paper that stated "Material reductions in the base ROE could lower the quality of and divert capital away from the transmission business, given its generally riskier profile than that for state-regulated utility businesses, such as distribution and generation. Moreover, investors could deploy capital to infrastructure projects with higher allowed returns, such as Commission-regulated natural gas pipelines, or to other industries generally."

130. Similarly, we disagree with Iowa Group's argument that any upward adjustment represents an improper attempt to "normalize" the DCF results to reflect normal capital market conditions. Any finding of anomalous capital market conditions and subsequent adjustments represents an attempt to counteract imprecision in the DCF model caused by capital market conditions and not a results-oriented attempt to raise the ROE to what it more typically is.

131. Trial Staff and others also argue that, if and when capital market conditions change, MISO TOs can request an increase in their effective ROE. As described above, anomalous market conditions may skew the current outputs of the DCF methodology, such that the mechanical application of the DCF methodology could provide an unjust and unreasonable ROE. Subsequent requests for rate increases would not address this shortcoming. The Commission also addressed this argument in Opinion 531-B where it found that transmission owners' "ability to subsequently request a rate increase if economic conditions change does not excuse the Commission from establishing an ROE under FPA section 206 that meets the requirements of *Hope* and *Bluefield*."[293]

132. We also disagree with arguments that the DCF methodology fully incorporates available information and investor expectations such that capital can be raised as inexpensively as the DCF results suggest. We find that such an outcome may not be the case due to model risk inherent in the DCF methodology in the presence of unusual market conditions. The finding that mechanical application of the DCF methodology may produce results inconsistent with *Hope* and *Bluefield* in certain circumstances is not inconsistent with the efficient market theory underlying the typical application of the DCF methodology in normal circumstances. Thus, consistent with the rationale explicated in Opinion No. 531, we disagree with Joint Customer Intervenors' assertion that the Presiding Judge erred in questioning the reliability of the DCF methodology in this proceeding based on the sources of information employed by this methodology.

133. We disagree with Joint Customer Intervenors' contention that the findings of the Presiding Judge in the Entergy Initial Decision are relevant to the ROE determination in this proceeding. Regardless of the timing of the study period in that proceeding, the findings in an initial decision, unless affirmed by the Commission, are not precedential.

134. We also disagree with Iowa Group's contention that any finding of anomalous capital market conditions and potential subsequent upward adjustment of the ROE is a "default" policy. In each proceeding, the Commission will evaluate the facts during the relevant period to determine whether capital market conditions are unusual and, if so, the Commission will consider alternative benchmark methodologies and state commission-

[293] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 50.

approved ROEs as additional evidence that might suggest that a mechanical application of the DCF results in an ROE insufficient to satisfy the requirements of *Hope* and *Bluefield*.[294] We also disagree with Iowa Group's assertion that there is no evidence that anomalous market conditions apply equally to DCF inputs from each member of the proxy group. This argument implies that MISO TOs would need to provide detailed studies of the effects of capital market conditions for each member of the proxy group, which would be unduly burdensome, if not impossible. Moreover, such a showing is unnecessary since capital market conditions apply across the entire economy and are not specific to individual utilities.

135. MISO TOs presented three alternative methodologies for estimating the cost of equity in this proceeding: a risk premium analysis, a capital asset pricing model (CAPM) analysis, and an expected earnings analysis. These alternative methodologies are the same ones that the Commission relied upon in Opinion No. 531 to corroborate the Commission's determination that a mechanical application of the DCF methodology results in an ROE that does not satisfy *Hope* and *Bluefield*. MISO TOs' risk premium analysis based upon Commission-authorized ROEs indicates that the Operating Companies' cost of equity is 10.36 percent.[295] MISO TOs' CAPM analysis produces a midpoint cost of equity estimate of 10.06 percent once an adjustment for the effect of firm size is made.[296] MISO TOs' expected earnings analysis produces a midpoint ROE range of 11.99 percent. Thus, all three alternative methodologies produce cost of equity estimates substantially in excess of the 9.29 percent midpoint of the zone of reasonableness produced by the DCF analysis in this case. As the Commission did in Opinion No. 531, we find that these analyses are informative and corroborate our decision to place MISO TOs' ROE at the central tendency of the upper half of the zone of reasonableness produced by our DCF analysis of the proxy group companies, rather than the midpoint.

136. In addition, the record indicates that all of the current state ROEs exceeded the 9.29 percent midpoint of the DCF zone of reasonableness in this case. The midpoint of the current state ROEs is 9.95 percent.[297] As the Commission explained in Opinion No. 531, in situations where our DCF methodology produces ROEs below those

---

[294] *See* Opinion No. 531, 147 FERC ¶ 61,234 at P 145.

[295] Exh. MTO-29 at 1.

[296] *See* Exh. MTO-1 at 95:9-18.

[297] Exh. MTO-42 at 1-2. *See* Exh. MTO-16 at 52-56. Ms. Lapson eliminated a Base ROE of 10.95 percent as an outlier.

approved at the state level, for functions that are riskier than the state-regulated functions, such a relationship might indicate that a mechanical application of the DCF methodology with the use of the central tendency of the resulting zone of reasonableness will not satisfy the requirements of *Hope* and *Bluefield*.

137. As the Commission found in Opinion No. 531, in considering these other methodologies and the ROEs allowed by state commissions, we do not depart from our use of the DCF methodology; rather, due to the presence of unusual capital market conditions, we find it appropriate to look to other record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness produced by the DCF methodology.[298] Below, we address the participants' arguments against each of MISO TOs' alternative ROE methodologies.

2. <u>CAPM</u>

138. Investors use CAPM analysis as a measure of the cost of equity relative to risk.[299] The CAPM methodology is based on the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. Specifically, the CAPM methodology determines the cost of equity by taking the "risk-free rate" and adding to it the "market-risk premium" multiplied by "beta."[300] The risk-free rate is represented by a proxy, typically the yield on 30-year U.S. Treasury bonds.[301] Betas, which are published by several commercial sources, measure a specific stock's risk relative to the market. The market risk premium is calculated by subtracting the risk-free rate from the expected return. The expected return can be estimated either using a backward-looking approach, a forward-looking approach, or a survey of academics and investment professionals.[302] A CAPM analysis is backward-looking if the expected return is determined based on historical, realized returns.[303] A CAPM analysis is forward-looking if the expected return is based on a DCF study of a large segment of

---

[298] Opinion No. 531, 147 FERC ¶ 61,234 at P 146.

[299] *Id.* P 147.

[300] Roger A. Morin, *New Regulatory Finance* 150 (Public Utilities Reports, Inc. 2006).

[301] *Id.* at 151.

[302] *Id.* at 155-162.

[303] *Id.* at 155-156.

the market.[304] Thus, in a forward-looking CAPM analysis, the market risk premium is calculated by subtracting the risk-free rate from the result produced by the DCF study.[305]

139. In this proceeding, MISO TOs submitted a forward-looking CAPM analysis of each company in the proxy group using the 2.7 percent 30-year U.S. Treasury bond yield for the risk-free rate, beta values for each proxy company reported by Value Line, and a market risk premium based on a DCF study of all dividend-paying companies in the S&P 500.[306] In that DCF study, MISO TOs added the weighted average dividend of those companies (2.4 percent) to the average of the weighted average growth rates projected for the companies by IBES and Value Line (8.9 percent). This resulted in a uniform cost of equity for the dividend-paying companies in the S&P 500 of 11.3 percent. The MISO TOs then subtracted from that figure the 2.7 percent risk-free rate to obtain a risk premium of 8.6 percent. The MISO TOs multiplied this risk premium by the beta listed for each proxy company by Value Line and added the risk-free rate to that product. This CAPM analysis produces an unadjusted ROE range of 7.86 percent to 10.87 percent for the proxy group, with a midpoint value of 9.37 percent.

140. However, after adjusting for the effect of each proxy company's size, MISO TOs' CAPM analysis produced an ROE range of 7.50 percent to 12.61 percent, with a midpoint value of 10.06 percent.[307] MISO TOs' witness, Dr. Avera, explained that the "size adjustment reflects the fact that differences in investors' required rate of return that are related to firm size are not fully captured by beta."[308] Dr. Avera based his size adjustments on data contained in a table published in Morningstar Inc.'s (Morningstar) "2015 Ibbotson SBBI Market Report." The table adjusts each proxy company's cost of equity based on its size, reducing the unadjusted cost of equity of larger companies, while increasing those of smaller companies.[309]

---

[304] *Id.* at 159-160.

[305] *See id.* at 150, 155.

[306] Exh. MTO-1 at 97-98.

[307] Initial Decision, 153 FERC ¶ 63,027 at P 264 (citing Exh. MTO-30 at 1).

[308] Exh. MTO-1 at 98.

[309] Exh. MTO-30 at 1.

a. **Initial Decision**

141. The Presiding Judge determined that the CAPM model offered by Dr. Avera was credible and supported allowing MISO TOs to earn a base ROE above the 9.29 percent midpoint of the zone of reasonableness.[310] The Presiding Judge explained that Dr. Avera's model was "substantially similar" to the CAPM that the Commission found useful in determining the placement of the base ROE in Opinion No. 531. The Presiding Judge rejected Mr. Gorman's contention that the growth rate used for the DCF analysis in Dr. Avera's CAPM was unsustainable and should be based, at least in part, on long-term growth rates, noting that the Commission had rejected this argument in Opinion No. 531-B on the grounds that the long-term growth rate does not necessarily apply to a curated set of large companies, like those included in the S&P 500. The Presiding Judge also rejected Mr. Gorman's arguments that Morningstar does not make size adjustments for companies with betas of less than 1.0, including public utilities, concluding that these arguments were not born out by the Morningstar data.[311]

142. The Presiding Judge also rejected Mr. Gorman's contention that, based on the utility industry's low beta, Morningstar also makes a downward "industry premium" adjustment that offsets any upward adjustment for size.[312] Mr. Gorman contended that Morningstar's SBBI 2013 Valuation Yearbook recommends an industry premium, as well as a size adjustment. Mr. Gorman stated that Morningstar recommends a negative industry premium adjustment for the electric-utility industry of between 3.4 percent and 4.09 percent. However, the Presiding Judge found that, on cross-examination, Mr. Gorman admitted that the Morningstar industry premium to which he referred was used for its "buildup method" of estimating cost of equity, and is not used to develop a CAPM.

143. The Presiding Judge also rejected the CAPM analysis advanced by Mr. Gorman and Mr. Hill, noting that it differed in several material respects from the CAPM that Commission relied upon in Opinion No. 531. The Presiding Judge noted, for instance, that this analysis did not use forward-looking data for its risk premium, nor did it use the 30-year U.S. Treasury bonds as its proxy for the risk-free rate of return, and that this analysis made no effort to adjust for the capitalization of the companies considered.[313]

---

[310] Initial Decision, 153 FERC ¶ 63,027 at P 313.

[311] *Id.* PP 268-269.

[312] *Id.* PP 270-271.

[313] *Id.* PP 280-283.

144. The Presiding Judge also rejected, as inconsistent with Opinion Nos. 531 and 531-B, arguments by Mr. Hill that Dr. Avera's model was invalid because it considered historical data and because it did not consider long-term growth rates.[314] The Presiding Judge also rejected Mr. Hill's criticism of Dr. Avera's size-based adjustments to the risk premium, concluding that they "fail[ed] to grasp, much less address, the rationale underlying the size adjustment."[315] The Presiding Judge also elected not to rely on Mr. Hill's CAPM on the grounds that it was partly backward looking, in contrast to the CAPM relied upon by the Commission in Opinion No. 531, and also because it addressed stock price appreciation rather than earnings growth and failed to adjust for the companies' market capitalization, which, as noted, is required by the CAPM model.[316]

145. The Presiding Judge also rejected the Joint Consumer Advocates' critiques of Dr. Avera's methodology, which were based largely on the testimony of Mr. Solomon, concluding that they were inconsistent with the Commission's reliance on a CAPM model in Opinion Nos. 531 and 531-B. In particular, the Presiding Judge noted that Mr. Solomon's critiques would have excluded companies that the Commission in Opinion No. 531-B found appropriate to include in the CAPM model.[317]

146. Finally, the Presiding Judge rejected Mr. Keyton's critiques of Dr. Avera's CAPM. The Presiding Judge concluded that Mr. Keyton's arguments regarding the sustainability of the growth the rates and the measure of a risk-free return used by Dr. Avera were effectively rejected by the Commission in Opinion No. 531-B, substantially for the reasons stated above.

b. <u>Briefs on Exceptions</u>

147. Complainants and other parties contend that the Presiding Judge erred by accepting Dr. Avera's CAPM analysis despite evidence demonstrating that flaws in the analysis render the results unreliable.[318] Complainants explain that Mr. Gorman

---

[314] *Id.* PP 284-286.

[315] *Id.* P 290.

[316] *Id.* PP 294-297.

[317] *Id.* PP 298-303.

[318] Complainants Brief on Exceptions at 48-51; Joint Customer Intervenors Brief on Exceptions at 43-47; OMS Brief on Exceptions at 33-37; Trial Staff Brief on Exceptions at 42-44.

proposed certain adjustments to correct Dr. Avera's CAPM analysis, such as replacing the size premium adjustment with an industry premium adjustment.[319] Complainants explain that the Presiding Judge stated that "Mr. Gorman failed to demonstrate that [the Morningstar] analysis is inappropriate for utilities."[320] Complainants state that the Presiding Judge appears to have misunderstood Mr. Gorman's proposal, which argues that Morningstar recognized that there are differences in risk that are not captured by the beta attributable to the industry in which a company operates.[321]

148. Complainants state that the Presiding Judge misunderstands Opinion No. 531 and Morningstar's methodology. Complainants aver that the Opinion No. 531 proceeding did not include evidence involving the industry risk premium and Morningstar's broad variation of the CAPM model to reflect firm size and industry risk. Complainants argue that Morningstar does not limit its risk return criteria to only a size adjustment, and instead uses all available and applicable information to accurately adjust the CAPM to reflect investment risk.[322] Complainants state that the Presiding Judge erred by concluding that the buildup method is not a variation of CAPM, and assert that Morningstar undertakes multiple adjustments from the base CAPM to account for both a size adjustment and an industry risk premium.[323]

149. Trial Staff states that Dr. Avera's CAPM calculation arrives at the weighted average growth rates projected for all dividend-paying companies on the S&P 500 through the use of both IBES and Value Line. Trial Staff further states that the Presiding Judge found that in Opinion No. 531, "the Commission found a CAPM using a format substantially similar to that used by Dr. Avera in this case to be a useful guide in determining the placement of the Base ROE," and that "Dr. Avera's CAPM is credible and supports allowing the MISO TOs' to collect a Base ROE above the Midpoint."[324] Trial Staff asserts, however, that this finding is in error because Dr. Avera's CAPM

---

[319] Complainants Brief on Exceptions at 48 (citing Exh. JC-9 at 20-22 (stating that an industry premium adjustment for the electric utility industry would be negative)).

[320] *Id.* at 49 (citing Initial Decision, 153 FERC ¶ 63,027 at P 281).

[321] *Id.* (citing Exh. JC-9 at 20-21).

[322] *Id.* at 49-50 (citing Exh. JC-9 at 21-22).

[323] *Id.* at 49-50.

[324] Trial Staff Brief on Exceptions at 42 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 310-311).

calculation in the Opinion No. 531 proceeding used only IBES growth rate projections.[325] Trial Staff states that Dr. Avera's CAPM calculation in the instant proceeding is contrary to the Commission's stated preference, which the Presiding Judge acknowledges in his Initial Decision, to use IBES as the source for growth rates and to use only one source for growth rates in a given calculation.[326] Trial Staff asserts that Opinion No. 531 leaves no doubt that it is "inappropriate to use estimates from different sources for different proxy group companies."[327] Trial Staff asserts that Dr. Avera's use of both IBES and Value Line data contradicts the Presiding Judge's finding in the Initial Decision that use of IBES alone is appropriate for growth rate projections used in the Commission's DCF analysis in this proceeding.[328]

150. Trial Staff argues that the Presiding Judge incorrectly concluded that (1) the beta component of the CAPM risk-premium calculation "serves to mitigate any differences" between the divergent growth rates used in Dr. Avera's CAPM and DCF analyses, and (2) the beta component of the CAPM "serves the same purpose as the long-term growth rate component" of the DCF.[329] Trial Staff argues that beta measures risk (i.e., the variability of expected returns) and is a different concept than a sustainable growth rate, which measures a firm's long-term expansion. Trial Staff, therefore, asserts that it is not possible for beta to mitigate an unsustainable growth rate or serve the same purpose as the long-term growth rate.[330]

151. Joint Customer Intervenors state that Dr. Avera used a 9 percent market risk premium instead of the independently-published Morningstar market risk premium of 6.2 percent.[331] Joint Customer Intervenors assert that had Dr. Avera used Morningstar's

---

[325] *Id.* (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 110 ("The growth rate in the NETOs' CAPM analysis is based on IBES data, which the Commission has long relied upon as a reliable source of growth rate data")).

[326] *Id.* at 43 (citing Initial Decision, 153 FERC ¶ 63,027 at P 43).

[327] *Id.* at 44 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 90).

[328] *Id.* at 43-44.

[329] *Id.* at 44 n.84 (citing Initial Decision, 153 FERC ¶ 63,027 at P 305).

[330] *Id.* n.84.

[331] Joint Customer Intervenors Brief on Exceptions at 44 (citing Exh. MTO-1 at 97).

6.2 percent market risk premium, his midpoint unadjusted ROE would have been just 7.5 percent.[332]

152. Joint Customer Intervenors assert that Dr. Avera inappropriately adjusted the theoretical construct based on his contentions that "financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size" and that "empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn somewhat less than predicted."[333] According to Joint Customer Intervenors, Dr. Avera's adjustments increased the CAPM-derived midpoint ROE from 9.53 percent to 10.24 percent.[334]

153. Joint Customer Intervenors state that Mr. Solomon noted that the Commission has previously rejected the use of the CAPM methodology because its beta does not fully capture and differentiate risks of common stocks, and argued that CAPM results are thus unreliable and should not be used. Joint Customer Intervenors assert that the Presiding Judge did not address the merit of this argument.[335]

154. Joint Customer Intervenors note that the Presiding Judge found that Dr. Avera's "decision to include only . . . short-term growth components inevitably skews his zone of reasonableness upward."[336] Joint Customer Intervenors contend that this finding indicates that for a DCF study of non-utility companies to produce a reasonable result, a second-stage growth rate must also be included. Joint Customer Intervenors argue, however, that Dr. Avera failed to apply a second-stage growth rate, which the Commission found necessary in Opinion No. 531. Joint Customer Intervenors state that the Presiding Judge recognized that the Commission reasoned in Opinion No. 531-B that "[w]hile an individual company cannot be expected to sustain high short-term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization."[337] Joint

---

[332] *Id.* (citing Exh. JCI-4 at 45:11-13).

[333] *Id.* at 44-45 (citing Exh. MTO-1 at 113).

[334] *Id.* at 45 (citing Exh. JCI-4 at 45:17-19; Exh. MTO-7 at 1).

[335] *Id.* at 44 (citing Exh. JCI-4 at 45:22-46:11).

[336] *Id.* at 45-46 (citing Initial Decision, 153 FERC ¶ 63,027 at P 328).

[337] *Id.* at 46 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 267 & 304; Opinion No. 531-B, 150 FERC ¶ 61,165 at P 113).

Customer Intervenors argue, however, that Dr. Avera's CAPM analysis did not use a stock index; rather it used a fixed portfolio of approximately 400 stocks picked *ex ante*. Moreover, Joint Customer Intervenors assert that the Presiding Judge effectively conceded that each company in that portfolio will see its growth trend towards the long-term GDP growth rate and, therefore, the portfolio as a whole must likewise trend towards the long-term GDP growth rate. Joint Customer Intervenors explain that the beta component of CAPM is a measure of stock volatility, and disagree with the Presiding Judge's finding that the "beta component serves the same purpose of the long-term growth-rate . . . ."[338]

155. Joint Customer Intervenors state that Dr. Avera's approach relies on a DCF analysis of approximately 400 dividend-paying companies culled from the S&P 500. Joint Customer Intervenors contend that, if the Commission has concerns about the accuracy of the DCF methodology employing a proxy group of electric utilities, it makes even less sense to depend on an aggregation of dividend-paying companies in the S&P 500. According to Joint Customer Intervenors, dividends are less important and less reliable for S&P 500 companies when compared to electric utilities, which have been known as relatively low risk, income-producing investments.[339]

156. OMS states that Dr. Avera's CAPM study for the instant proceeding, which incorporates Value Line growth estimates, differs materially from his CAPM study cited in Opinion No. 531, which relied on growth rates taken from Yahoo! Finance's reporting of IBES estimates.[340] OMS asserts that Value Line growth estimates are substantially backward-looking, and notes that the Initial Decision found Value Line to be inferior in a separate passage.[341]

157. OMS argues that the Presiding Judge erred by treating beta as a substitute for second-stage growth. OMS states that beta is a measure of volatility, or systematic risk, of a security or a portfolio in comparison to the market as a whole.[342] OMS states that,

---

[338] Joint Customer Intervenors Brief on Exceptions at 46-47 (citing Initial Decision, 153 FERC ¶ 63,027 at P 305).

[339] *Id.* at 45.

[340] OMS Brief on Exceptions at 37 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 110; Exh. MTO-30 at 1, note (b)).

[341] *Id.* (citing Initial Decision, 153 FERC ¶ 63,027 at PP 48-49).

[342] OMS Brief on Exceptions at 36 (citing Andrew J. Cueter, *Using Beta* (Oct. 2012),

(continued...)

while the beta for utility stock consistently averages well below 1.0, exceptions in which a utility stock's beta exceeds 1.0 and thus increases that proxy's CAPM result, are Common.[343] OMS states that the second-stage growth rate, on the other hand, is necessary to incorporate the effect of changes in the general economy (as represented by GDP growth) in forecasting the long-term growth of an individual company or group of companies. According to OMS, the second-stage growth rate is part of getting to a reliable number for the expected long-term return on a fully diversified equity portfolio – an essential ingredient for a CAPM study to produce any sort of useful result. OMS argues that to equate beta and the second-stage growth rate because in this particular instance "[e]ach serves to lower the top of the zone of reasonableness" is not well-reasoned.[344]

158. OMS states that the growth component of the portfolio return calculation used by Dr. Avera weighted short-term growth rates forecasted by IBES and Value Line at 100 percent, thereby assuming that the growth rates over the next five years will continue forever. OMS asserts that this premise is implausible and flies in the face of the Commission's determination in Opinion No. 531 to use a weighted average of short and long-term growth rates in its two-step DCF analysis. OMS states that the failure to incorporate a blended growth rate is the precise reason the Presiding Judge rejected Dr. Avera's DCF study of non-utility companies, wherein the Presiding Judge observed that "[Dr. Avera's] decision to include only dividend yields and short-term growth components inevitably skews his zone of reasonableness upward."[345] OMS argues that it is arbitrary and capricious for the Initial Decision to reject one of Dr. Avera's studies for its failure to incorporate long-term growth rates, while adopting another that suffers from precisely the same flaw.[346]

---

http://www.valueline.com/Tools/Educational_Articles/Stocks/Using_Beta.aspx#.Vp5VhZorJaQ).

[343] *Id.* at 36 (citing Richard A. Michelfelder and Panayiotis Theodossiou, *Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings* (Nov. 2013), at 60, 66 (showing in Figure 1 that the top decile of utility betas exceeded 1.0 for some years and the highest utility beta exceeded 1.0 in most years)).

[344] *Id.* at 36-37 (citing Initial Decision, 153 FERC ¶ 63,027 at P 305).

[345] OMS Brief on Exceptions at 34 (citing Initial Decision, 153 FERC ¶ 63,027 at P 328).

[346] *Id.*

159. OMS acknowledges that Opinion No. 531-B rejected arguments that the Commission erred by adopting a CAPM formulation that failed to include a second-stage growth rate. OMS states that, consistent with Opinion No. 531-B, the Presiding Judge held that "[w]hile an individual company cannot be expected to sustain high short-term growth rates into perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization."[347] OMS contends, however, that such reasoning makes no more sense in the Initial Decision than it did before.[348]

160. OMS states that, in rejecting Dr. Avera's non-utility DCF analysis for its failure to incorporate a second-stage growth factor, the Presiding Judge implicitly recognized that, over time, each individual company in Dr. Avera's portfolio will see its growth rate trend downward toward the long-term GDP growth rate. OMS asserts that, if each company in the portfolio will see its growth rate trend toward the GDP growth rate, so also will the portfolio as a whole. OMS, therefore, contends that the CAPM calculation is illogical and indefensible.[349]

161. OMS asserts that the rationale, as stated in Opinion No. 531 and adopted by the Initial Decision, simply does not apply. OMS explains that the portfolio Dr. Avera used in his CAPM study was not the S&P 500 itself, with a constantly updated cast of high-capitalization companies; rather, it was a fixed portfolio of 400 stocks. OMS stresses that the 400 stock portfolio will not be "regularly updated" to include only companies with high market capitalizations.[350]

c. <u>Briefs Opposing Exceptions</u>

162. MISO TOs contend that the Presiding Judge correctly accepted Dr. Avera's CAPM analysis and correctly found that this analysis supports establishing a base ROE above the midpoint. MISO TOs argue that the arguments raised by Complainants, Joint Customer Intervenors, and OMS were all considered and rejected in Opinion No. 531-B and thus were appropriately rejected, implicitly or explicitly, in the Initial Decision.[351]

---

[347] *Id.* at 35 (citing Initial Decision, 153 FERC ¶ 63,027 at P 304 (quoting Opinion No. 531-B, 150 FERC ¶ 61,165 at P 113)).

[348] *Id.*

[349] *Id.* at 35-36.

[350] *Id.* at 35.

[351] MISO TOs Brief Opposing Exceptions at 28.

MISO TOs state that Opinion No. 531-B analyzed and found meritless arguments critical of Dr. Avera's CAPM analysis because Dr. Avera (1) performed a DCF study on the S&P 500, (2) employed a size adjustment, (3) did not employ a long-term growth component, and (4) relied on betas based on historical data as a risk measure.[352]

163. MISO TOs argue that Complainants' advocacy for Mr. Gorman's CAPM analysis does not withstand scrutiny because Mr. Gorman's CAPM market premium is not based on a DCF analysis or any other forward-looking approach. MISO TOs assert that Mr. Gorman's use of Morningstar's buildup method is distinct from, and not used in, the CAPM methodology.[353] Furthermore, MISO TOs state that the publication on which Mr. Gorman relied only applies an industry-based adjustment factor to the buildup method of estimating risk premiums and not to the well-established CAPM that Dr. Avera employed and that the Commission accepted in Opinion No. 531.[354]

164. With regard to Trial Staff's objections to Dr. Avera's use of both IBES and Value Line growth rate estimates in his CAPM analysis, MISO TOs assert that the Presiding Judge cited Dr. Avera's CAPM analysis for the limited purpose of informing placement of the base ROE within the zone of reasonableness. MISO TOs argue that the Presiding Judge did not explicitly find that only IBES growth rate data are acceptable for purposes of applying the DCF model.[355]

d. <u>Commission Determination</u>

165. We affirm the Presiding Judge's findings that the MISO TOs' witness, Dr. Avera, properly performed his CAPM analysis and that the CAPM methodology supports the Commission's determination that the mechanical application of the DCF methodology results in an ROE that is inconsistent with *Hope* and *Bluefield*.

166. With regard to MISO TOs' size premium adjustment, the Commission stated in Opinion No. 531-B that the use of such an adjustment was "a generally accepted approach to CAPM analyses."[356] The Commission explained that "[t]he purpose of the

---

[352] *Id.* at 28-29.

[353] *Id.* at 29 (citing Complainants Brief on Exceptions at 48-51).

[354] *Id.* at 29-30 (citing Initial Decision, 153 FERC ¶ 63,027 at P 271).

[355] *Id.* at 31.

[356] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 117.

. . . size adjustment is to render the CAPM analysis useful in estimating the cost of equity for companies that are smaller than the companies that were used to determine the market risk premium in the CAPM analysis."[357] Moreover, Mr. Gorman acknowledged that Morningstar proposes to add a size premium adjustment to the CAPM return because research suggests that systematic risk for small companies may not be completely reflected in the company's beta.[358] While Mr. Gorman asserted that Morningstar uses portfolios with a beta greater than one and the national proxy group has a beta less than one,[359] he does not explain how or why that fact would produce overstated results that would bar MISO TOs from making a size premium adjustment. Indeed, nothing in the record supports the notion that there is a correlation between beta and the size premium adjustment used by MISO TOs. As such, we are not persuaded by Complainants' and Joint Customer Intervenors' assertions that the size premium adjustment that is used by Morningstar cannot be used by MISO TOs.[360] For these reasons, we reject Complainants' argument that the size premium adjustment is flawed.

167. With regard to Complainants' proposed industry premium adjustment, the primary issue is whether it should be included in CAPM analyses or it should be limited to Morningstar's buildup method of determining the cost of equity. Complainants assert that the buildup method is a variation of CAPM. However, a thorough examination of Morningstar's buildup method reveals that the underlying formula differs from the generally accepted CAPM formula.[361] Indeed, the buildup method formula used by Morningstar does not consider beta, a fundamental input used in CAPM analyses. Therefore, as an initial matter, we affirm the Presiding Judge's conclusion that Mr. Gorman has failed to demonstrate that Morningstar's use of an industry premium adjustment in its buildup method has any relevance to CAPM analyses.[362]

---

[357] *Id.* P 117.

[358] Exh. JC-9 (corrected) at 20-21.

[359] *Id.* at 20.

[360] *See* Initial Decision, 153 FERC ¶ 63,027 at P 281.

[361] Exh. MTO-59 at 6 (the buildup method formula used by Morningstar is as follows: Cost of Equity Estimate = Riskless Rate + Equity Risk Premium + Industry Risk Premium + Size Premium). For comparison, the CAPM formula is as follows: Required return = Risk-free Rate + Beta x (Expected Return – Risk-free Rate). *See* Initial Decision, 153 FERC ¶ 63,027 at P 259 (citing Exh. JC-9 at 41:2-10).

[362] *See* Initial Decision, 153 FERC ¶ 63,027 at P 271.

168. Nevertheless, Complainants assert that an industry premium adjustment to the CAPM analysis is necessary. Therefore, they bear the burden of demonstrating that the inclusion of this adjustment is appropriate. Morningstar explains that the industry premium "measures how risky the industry is in relation to the market as a whole, regardless of size."[363] As discussed above, beta, like the industry risk premium, is a measure of risk relative to the market. We note that every company in the national proxy group has a beta of less than one.[364] From that, we conclude that the betas already reflect the fact that the proxy group companies are low risk relative to the market generally. Accordingly, because the betas already reflect the relative risk of the industry, we conclude that it would be inappropriate to add an industry risk premium to the CAPM analyses.

169. Trial Staff argues against the use of Value Line growth rates in MISO TOs' CAPM analysis. While the Commission has found that Value Line's growth rate estimates are not acceptable as the short-term consensus growth rate input for the two-step DCF model, the Commission has nevertheless found that Value Line is a valid source of general financial data. In the instant CAPM analysis, the Value Line data is used in conjunction with IBES data and both are averaged over a 400-company data set. This use of growth rate data is fundamentally different from how growth rate data is used in our DCF model, because it is intended to provide a less precise cost of equity estimate than the DCF model. Although we require more precision from our DCF model—as the primary financial model that we use, and have used for decades, to determine public utility ROEs—that same degree of precision is less essential in the CAPM analysis because that analysis is but one of multiple pieces of evidence corroborating the results of our DCF analysis. Furthermore, no party demonstrated that the Value Line growth rate estimates for dividend-paying S&P 500 companies are unreasonably high or low, or that reliance on IBES growth rate estimates alone would produce a materially different CAPM result using data from the study period. For these reasons, we conclude that MISO TOs' use of both IBES and Value Line growth rate estimates in their CAPM analysis is reasonable for purposes of corroborating the results of the DCF analysis.

170. While we agree with Trial Staff, Joint Customer Intervenors, and OMS that beta does not serve the same function as the long-term growth rate component of the DCF,[365] we note that a long-term growth rate component is not required in the DCF study used to develop the market risk premium for MISO TOs' CAPM analysis. As the Commission

[363] Exh. MTO-59 at 4.

[364] *See* Exh. MTO-30 at 1-2.

[365] Trial Staff Brief on Exceptions at 44 n.84.

explained in Opinion No. 531-B, the rationale for requiring a two-step DCF methodology that incorporates a long-term growth rate input when conducting a DCF study on a specific group of public utilities does not necessarily apply when conducting a DCF study of the companies in the S&P 500. While it is often unrealistic and unsustainable for high short-term growth rates for an individual company to continue in perpetuity, the S&P 500 is regularly updated to only include companies with high market capitalization.[366] Joint Customer Intervenors and OMS argue that this rationale does not apply because MISO TOs did not rely on the S&P 500 index, but instead studied approximately 400 dividend-paying companies culled from the S&P 500. We disagree. MISO TOs did not arbitrarily select companies; they selected every dividend-paying stock included in the S&P 500, a group that is regularly updated.[367] As such, it is indisputable that each company selected by MISO TOs had a high market capitalization at that time. Therefore, consistent with Opinion No. 531-B, we find that the DCF study of the approximately 400 dividend-paying stocks selected by MISO TOs need not include a two-step DCF methodology that incorporates a long-term growth rate input.

171. Joint Customer Intervenors assert that MISO TOs' CAPM analysis should have used the Morningstar market risk premium of 6.2 percent, which was based on the arithmetic average difference between stocks and Treasury bills from 1926 to 2013.[368] However, the Morningstar market risk premium relies on historical data and, therefore, any CAPM analyses using the Morningstar market risk premium would be backward-looking.[369] Joint Customer Intervenors, therefore, request that the Commission accept a backward-looking CAPM analysis despite the fact that the Commission has historically accepted forward-looking CAPM analyses and rejected backward-looking CAPM analyses.[370] Accordingly, we reject Joint Customer Intervenors' requested use of the

---

[366] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 113.

[367] *See* Initial Decision, 153 FERC ¶ 63,027 at P 260. Non-dividend paying S&P companies must be excluded from the DCF analysis, because a DCF analysis cannot be performed for a non-dividend paying company.

[368] Exh. JCA-1 at 21:21-27.

[369] *See* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 108 (citing Roger A. Morin, *New Regulatory Finance* 155-156 (Public Utilities Reports, Inc. 2006)).

[370] Initial Decision, 153 FERC ¶ 63,027 at PP 279-280 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 147 n.292).

Morningstar market risk premium because doing so would result in a CAPM analysis that is not representative of the capital market conditions present during this proceeding.[371]

172. For the reasons stated above, we affirm the Presiding Judge's acceptance of the CAPM analysis to be used as corroborative evidence, in determining whether the midpoint of the zone of reasonableness produced by the Commission's DCF analysis provides a return that satisfies the requirements of *Hope* and *Bluefield*.[372]

3. <u>Risk Premium</u>

173. The risk premium methodology, in which interest rates are a direct input, is "based on the simple idea that since investors in stocks take greater risk than investors in bonds, the former expect to earn a return on a stock investment that reflects a 'premium' over and above the return they expect to earn on a bond investment."[373] As the Commission found in Opinion No. 531, investors' required risk premiums expand with low interest rates and shrink at higher interest rates. The link between interest rates and risk premiums provides a helpful indicator of how investors' required returns on equity have been impacted by the interest rate environment.

174. Multiple approaches have been advanced to determine the equity risk premium for a utility.[374] For example, a risk premium can be developed directly, by conducting a risk premium analysis for the company at issue, or indirectly by conducting a risk premium analysis for the market as a whole and then adjusting that result to reflect the risk of the company at issue.[375] Another approach for the utility context is to "examin[e] the risk premiums implied in the returns on equity allowed by regulatory commissions for utilities

---

[371] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 118 (finding that a CAPM study is reliable and sufficiently representative of capital market conditions if it is prospective and does not pre-date the Great Recession).

[372] *See* Initial Decision, 153 FERC ¶ 63,027 at P 311.

[373] Opinion No. 531, 147 FERC ¶ 61,234 at P 147 (citing Roger A. Morin, New Regulatory Finance 108 (Public Utilities Reports, Inc. 2006).

[374] *See generally* Roger A. Morin, *New Regulatory Finance* 107-130 (Public Utilities Reports, Inc. 2006).

[375] *Id.* at 110.

over some past period relative to the contemporaneous level of the long-term U.S. Treasury bond yield."[376]

175. MISO TOs' witness, Dr. Avera, followed a variation of the latter approach, developing a risk premium study by analyzing the ROEs allowed by this Commission for the period from 2006 through 2014, relative to the contemporaneous level of the yield of BBB-rated bonds, to calculate equity risk premiums for each year during that period.[377] Dr. Avera then averaged these annual risk premiums to determine an average risk premium for the entire 2006-2014 period of 4.77 percent.[378]

176. Dr. Avera next adjusted this risk premium to reflect the tendency of risk premiums to rise as interest rates fall. Dr. Avera stated that the average yield of bonds rated BBB by S&P during the period 2006 to 2014 was 5.90 percent. However, the average yield of bonds rated Baa by Moody's during the January-June 2015 period used for the DCF analysis in this case was 4.55 percent, a difference of 1.35 percent.[379] This difference reflects the extent to which current bond yields have fallen below the 2006-2014 average. Based on MISO TOs' regression analysis of the annual equity risk premiums he calculated for each of the nine years from 2006 to 2014, the risk premium during that period increased by approximately 77.07 basis points for each percentage drop of the BBB-rated bond yields.[380] By applying the 77.07 basis point coefficient to the 1.35 percent reduction in bond yields, Dr. Avera calculated a risk premium adjustment of 1.04 percent, which Dr. Avera added to the 4.77 percent average risk premium for the 2006-2014 period to calculate an adjusted risk premium for the six-month DCF study period of 5.81 percent. Finally, Dr. Avera added the 5.81 percent adjusted risk premium to the 4.55 percent Baa-rated bond yield during the six-month DCF study period to calculate a risk premium-based cost of equity of 10.36 percent.[381]

---

[376] *Id.* at 123.

[377] Exh. MTO-29 at 3; *see also* Exh. MTO-29 at 3.

[378] Exh. MTO-1 at 101:18-19.

[379] Exh. MTO-29 at 1. MISO TOs treated BBB and Baa rate bonds as having equivalent yields.

[380] *See* Exh. MTO-29 at 6.

[381] Exh. MTO-29 at 1; *see also* Initial Decision, 153 FERC ¶ 63,027 at PP 233-235.

a. Initial Decision

177. The Presiding Judge determined that the risk premium model offered by Dr. Avera was valid and supports awarding MISO TOs a base ROE above the midpoint of the zone of reasonableness. The Presiding Judge noted that the Commission in Opinion No. 531 accepted Dr. Avera's risk-premium analysis and that he had supported his contention that the risk premium rises as the interest rates fall with numerous authorities.[382] The Presiding Judge rejected Mr. Gorman's risk premium model, observing that it was "appreciably different" from the analysis used by the Commission in Opinion No. 531 and that Mr. Gorman did not justify these differences. The Presiding Judge also noted that Mr. Gorman did not address the inverse relationship between bond yields and the risk premium that the Commission "endorsed" in Opinion No. 531.

178. The Presiding Judge also rejected the criticisms of the risk premium model advanced by various witnesses, noting that, although they might be a reason not to rely on the risk premium model in lieu of a DCF analysis, they did not demonstrate that it shouldn't be used as a check on the DCF model.[383] Relying on the Commission's determinations in Opinion No. 531-B, the Presiding Judge also rejected arguments that risk premium model suffered from regulatory lag—the idea that bond yields were not contemporaneous with the various study periods—and that the risk premium analysis was flawed because many of the included ROEs were set by settlement. Finally, the Presiding Judge rejected critiques of Dr. Avera's sample size and statistical methodology, noting that they were equivalent or superior to those that the Commission accepted and relied upon in Opinion No. 531.

b. Briefs on Exceptions

179. Complainants argue that Dr. Avera's risk premium analysis, which the Initial Decision adopted, is inconsistent with the finding of anomalous market conditions. Complainants contend that, because the Initial Decision found that current market conditions are unsustainable, it is inappropriate to accept Dr. Avera's risk premium model, which Complainants assert is based on an unsustainable relationship between equity returns and bond yields during a period of unsustainable capital market conditions.[384]

---

[382] Initial Decision, 153 FERC ¶ 63,027 at P 260.

[383] *Id.* P 241.

[384] Complainants Brief on Exceptions at 37-39.

180. Complainants assert that Dr. Avera's risk premium analysis is flawed because the regression study is based on only nine observations (the annual equity risk premiums for each year from 2006 to 2014). Complainants note that, rather than looking at the individual company-authorized ROEs, Dr. Avera made simplifying assumptions that likely increased the results.[385] Complainants also allege that, rather than relying on independent market participants' projected Baa-rated bond yield, Dr. Avera developed his own projected utility bond yield.[386] Complainants further assert that Dr. Avera's adjustments to the data produce excessive ROEs based on today's current capital market environment.[387] Complainants also cite to arguments from Mr. Solomon and Mr. Hill regarding flaws in the risk premium analysis.[388]

181. Complainants state that Dr. Avera's risk premium analysis should be disregarded and that Mr. Gorman's risk premium analysis should be considered.[389] According to Complainants, unlike Dr. Avera's risk premium analysis, Mr. Gorman's risk premium analysis is based on two estimates of equity return over the period of 1986 to 2015 to account for variations of the risk premium based on market conditions and investor risk perceptions.[390] Complainants explain that Mr. Gorman's risk premium analysis using U.S. Treasury bonds resulted in a range of 8.25 percent to 10.57 percent, his risk premium analysis using Baa-rated bonds resulted in a range of 7.53 percent to 10.13 percent, and the two analyses together resulted in a range of 7.53 percent to 10.57 percent with a midpoint of 9.05 percent.[391]

182. Complainants state that the current A-rated utility-bond yield to U.S. Treasury bond yield spread is approximately 116 basis points, while the 36-year average A-rated

[385] *Id.* at 45-46 (citing Exh. JC-9 at 27). Mr. Gorman seems to have argued that Dr. Avera erred by relying on the average authorized returns for each year, thereby weighing each of the eight authorized returns from 2013 less than each of the five authorized returns from 2014.

[386] *Id.* at 46 (citing Exh. JC-9 at 28).

[387] *Id.* at 46 (citing Exh. JC-9 at 28-29).

[388] *Id.* at 46-47 (citing Exh. JCI-4 at 41, Exh. JCA-11 at 36-42).

[389] *Id.* at 47.

[390] *Id.* at 39-40 (citing Exh. JC-9 at 47).

[391] *Id.* at 42-43 (citing Exh. JC-22 at 17).

utility-bond yield spread is 152 basis points. Complainants further state that the current Baa-rated utility-bond yield to U.S. Treasury bond yield spread is approximately equal to the 36-year average utility-bond yield spread. According to Complainants, the utility-bond yield spreads are evidence that the market considers electric utilities to be relatively low-risk investments and that utilities continue to have strong access to capital markets.[392]

183. Joint Customer Intervenors contend that several witnesses demonstrated flaws in Dr. Avera's risk premium analysis. Joint Customer Intervenors assert that the Initial Decision improperly rejected the identification of flaws in Dr. Avera's regression analysis on the basis that the Commission accepted the methodology in Opinion No. 531. Joint Customer Intervenors argue, however, that MISO TOs broadened the limited purpose for which the alternative analyses were used in Opinion No. 531 and that the flaws identified in the instant proceeding were not considered in Opinion No. 531.[393]

184. Joint Customer Intervenors argue that Dr. Avera's risk premium analysis was flawed because it relied completely on historical data, inconsistent with the Commission's long-established policy that the ROE methodology must be forward-looking.[394] Joint Customer Intervenors contend that the use of a historical risk premium analysis in conjunction with a forward-looking DCF analysis amounts to an unreliable mismatch.[395]

185. Joint Customer Intervenors contend that the Initial Decision dismissed their witness Mr. Solomon's arguments without addressing them.[396] First, Joint Customer Intervenors assert that Dr. Avera's risk premium analysis lacked a direct equity market input, thereby producing an unreliable and inflated estimate of the current cost of common equity capital. Second, Joint Customer Intervenors also assert that Dr. Avera's risk premium analysis' use of interest rates and risk premiums as the only inputs in its

---

[392] *Id.* at 42.

[393] Joint Customer Intervenors Brief on Exceptions at 39-43.

[394] *Id.* at 40 (citing Exh. JCI-4 at 41:15-16; *S. Cal. Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070 (2000)).

[395] *Id.*

[396] *Id.* at 40-42 (citing Initial Decision, 153 FERC ¶ 63,027 at P 255; *NorAm Gas Transmission Co. v. FERC*, 148 F.3d 1158, 1165 (D.C. Cir. 1998)).

regression analysis failed to consider other factors that influence risk premiums and thus cannot account for historical volatility in risk premiums.[397]

186. According to Joint Customer Intervenors, Mr. Solomon demonstrated that more recent data indicates that Dr. Avera's analysis was upwardly and improperly biased. Joint Customer Intervenors state that Dr. Avera's risk premium analysis calculated a 5.62 percent risk premium for the DCF study period during the first half of 2015, which Joint Customer Intervenors point out is 27 basis points above the 5.35 percent risk premium Dr. Avera observed for 2014.[398]

187. Joint Customer Intervenors also state that Dr. Avera's risk premium analysis calculated that, for every 1 percent drop in utility bond yields, the cost of equity capital goes down by just under 23 basis points. Joint Customer Intervenors note, however, that Dr. Avera concluded in a separate state commission-based risk premium analysis that ROEs declined over 57 basis points for every 1 percent reduction in the average utility bond yield. Joint Customer Intervenors argue that the disparity between the two analyses further supports placing no reliance on the results of such historical analyses.[399]

188. OMS asserts that Dr. Avera's risk premium study is fatally flawed by the inclusion of at least one data point that is demonstrably invalid and results in a grossly excessive risk premium. OMS states that one of the Base ROE decisions that Dr. Avera included in his data set can in no way be considered a cost of equity determination and, therefore, had no place in the data set of historic risk premiums.[400] OMS states that *ITC Holdings* was merely a docketing order insofar as ROE is concerned; it established that litigation of a just and reasonable ROE for the Entergy Operating Companies' transmission assets would be determined prospectively in the instant proceeding, rather than in the Entergy transmission rate docket. OMS argues that, by treating *ITC Holdings* the same as other orders where the Commission actually calculated a just and reasonable return for a company, Dr. Avera grossly inflated the historical risk premium.[401]

---

[397] *Id.* at 41 (citing Exh. JCI-4 at 51:17-20, 42:1-15).

[398] *Id.* at 41-42 (citing Exh. MTO-6 at 3).

[399] *Id.* at 43 (citing Exh. MTO-10).

[400] OMS Brief on Exceptions at 31 (citing *ITC Holdings Corp.,* 143 FERC ¶ 61,257 (2013), *order on reh'g*, 146 FERC ¶ 61,111, at P 25 (2014) (*ITC Holdings*)).

[401] *Id.*

189. OMS states that it is a straightforward matter to correct the errors committed by Dr. Avera. OMS states that the Commission may take administrative notice of its past decisions and those decisions' underlying bases to the extent necessary to consider OMS' corrected version of Exhibit No. MTO-29.[402] OMS states that, by limiting the data points to actual base ROE determinations, its corrected version of Exhibit No. MTO-29 produces a value significantly lower than 10.32 percent.[403]

c. <u>Briefs Opposing Exceptions</u>

190. MISO TOs argue that the Presiding Judge correctly accepted Dr. Avera's risk premium analysis, and that his analysis simply serves as a check on the midpoint of the DCF range, and not the cost of capital model used to set the authorized ROE. MISO TOs assert that the Commission has previously accepted Dr. Avera's approach for its limited purpose.[404] MISO TOs state that the Presiding Judge properly concluded that Mr. Gorman's alternate risk premium analysis was "unreliable and produced cost of equity estimates that were unrepresentatively low."[405] MISO TOs disagree with OMS' characterization of the Commission's decision in *ITC Holdings* as "merely a docketing order insofar as ROE is concerned."[406] MISO TOs assert that the Commission found the current 12.38 percent ROE to be just and reasonable for Entergy as a MISO transmission owner, and rejected arguments for a different ROE.[407]

---

[402] *Id.* at Attachment 1 (removing or revising various data points from the list compiled by MISO TOs).

[403] OMS Brief on Exceptions at 32-33. OMS proposes a risk premium cost of equity of 9.94 percent. *Id.*, Attachment 1.

[404] MISO TOs Brief Opposing Exceptions at 24 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at PP 97-101).

[405] *Id.* at 26.

[406] *Id.* (citing OMS Brief on Exceptions at 31); *see ITC Holdings*, 146 FERC ¶ 61,111.

[407] MISO TOs Brief Opposing Exceptions at 27 (citing *ITC Holdings*, 146 FERC ¶ 61,111 at P 60).

d. **Commission Determination**

191. We affirm the Presiding Judge's findings that the MISO TOs' risk premium study is valid and supports awarding the MISO TOs a base ROE above the midpoint. We disagree with Complainants' assertion that risk premium analyses cannot be relied upon during a period of anomalous capital market conditions. The Commission has already considered this question. In Opinion No. 531, the Commission stated that alternative methodologies serve as additional evidence to gain insight into the potential impacts of unusual capital market conditions on the appropriateness of using the resulting midpoint. The Commission found the risk premium analysis to be informative, and used it and other alternative methodologies to inform the placement of the just and reasonable ROE within the zone of reasonableness established by the DCF methodology.[408] Consistent with this precedent, we find that, as a general matter, it is appropriate to rely on risk premium analyses as corroborative evidence during periods of anomalous capital market conditions.

192. With regard to assertions regarding the number of observations in MISO TOs' regression analysis, we find that the nine-year period is sufficiently large to inform a risk premium study. Since the issuance of Order No. 679, when the Commission commenced setting "up-front ROEs," a substantial amount of ROE data points became available. Moreover, MISO TOs' regression analysis covers a period both before and after the financial crisis, and considers approximately 80 Commission-accepted ROE data points over the nine-year period.[409] Neither Complainants nor Complainant-aligned parties provided additional Commission-accepted ROE data points for the years preceding 2006, so we have no evidence that doing so would substantially impact MISO TOs' regression analysis.[410]

193. While Complainants suggest that each ROE data point should be its own observation in the regression analysis, we are not persuaded that doing so would be superior to MISO TOs' regression analysis, based on the nine annual equity premiums

---

[408] Opinion No. 531, 147 FERC ¶ 61,234 at PP 145-146.

[409] Exh. MTO-29 at 4-5.

[410] Complainants' risk premium analysis considers state commission-accepted ROEs for the period from 1986 through March 2015. *See* Exh. JC-19. The Commission rejected the results of a similar risk premium study due to the risk differential between state-regulated distribution and Commission-regulated interstate transmission. Opinion No. 531-B, 150 FERC ¶ 61,165 at P 99. Accordingly, we reject Complainants' risk premium analysis.

during the years 2006-2014. Complainants' proposal would require each ROE data point to be matched with the bond yield that existed on the date of the Commission's acceptance of that data point.[411] However, Complainants have not demonstrated why the bond yield on that specific date is more representative of the interest rate environment than the average annual bond yields used by MISO TOs. Indeed, there is no fixed relationship – and there is a lag – between dates of the relevant study period and the date on which the Commission adopts an ROE, with the variation depending on the facts of the case. Therefore, it seems that assigning the bond yield on one specific date to each data point would add an unnecessary amount of volatility to the regression analysis. Furthermore, the Commission already held in Opinion No. 531-B that assigning approximate dates to the cost of equity determinations is often unavoidable and does not undermine the relevance of risk premium analyses. For these reasons, we find that the methodology used by MISO TOs in their regression analysis is appropriate.

194. We also reject Complainants' argument that MISO TOs should have relied on independent market participants' projected Baa-rated bond yield. The Presiding Judge held that projected yields used in risk premium analyses are speculative and less reliable than historical yields, and rejected Dr. Avera's use of projected Baa-rated bond yields. As an initial matter, we agree with the Presiding Judge and, for that reason, reject Complainants' argument.

195. With regard to Joint Customer Intervenors' argument that MISO TOs' risk premium analysis was flawed because it relied completely on historical data, we note that the risk premium analysis accepted in Opinion No. 531-B was based on "empirical observations and regression analysis of bond yields and Commission-allowed ROEs"— i.e., forms of historical data.[412] In any event, because the risk premium analysis uses regulated ROEs, it would be inappropriate to attempt to project what such ROEs would be. Moreover, despite Joint Customer Intervenors' assertion that MISO TOs' risk premium analysis is inconsistent with the Commission's policy that the ROE methodology must be forward-looking, we are not relying on the risk premium analysis to set the ROE itself. Instead, we find that MISO TOs' risk premium analysis is sufficiently reliable to corroborate our decision to place MISO TOs' base ROE above the midpoint of the zone of reasonableness produced by the DCF analysis.[413]

---

[411] Exh. JC-9 (corrected) at 27.

[412] Opinion No. 531-B, 150 FERC ¶ 61,165 at PP 97-101.

[413] *Id.* P 98.

196. We disagree with Joint Customer Intervenors' assertion that MISO TOs' risk premium analysis is flawed because it lacks a direct market input and fails to consider other factors that influence risk premiums. MISO TOs' risk premium analysis is similar to the risk premium analysis accepted in Opinion No. 531-B. Therefore, in order to demonstrate that MISO TOs' risk premium analysis is flawed, Joint Customer Intervenors must either raise and reasonably support new arguments that were not considered in the Opinion No. 531 proceeding, or differentiate between the two risk premium analyses. Joint Customer Intervenors fail to do either. For example, Joint Customer Intervenors generically claim that MISO TOs' risk premium analysis is lacking, but do not propose specific factors that should be considered. As a result, we have no basis to conclude that any further considerations are necessary. Moreover, while Joint Customer Intervenors claim that MISO TOs' risk premium analysis cannot account for historical volatility, they fail to demonstrate that this purported historical volatility would result in materially different risk premium results.[414]

197. Joint Customer Intervenors disagree with MISO TOs' regression analysis and its result: for every percentage drop of the BBB-rated bond yields, the risk premium increased approximately 77.07 basis points and, therefore, the cost of equity capital would decrease by approximately 22.93 basis points. We note, however, that the 77.07 basis point coefficient proposed by MISO TOs is substantially less than the 93 basis point coefficient in the analysis that the Commission relied upon in Opinion No. 531-B.[415] Furthermore, despite Joint Customer Intervenors' arguments to the contrary, the Commission held in Opinion No. 531-B that it was not persuaded by arguments that the results of a Commission-based risk premium analysis "are invalid simply because they differ from the inferred rate relationship reflected in historical state commission-approved ROEs, particularly where anomalous capital market conditions exist that may impact the inferred relationship between risk premiums and interest rates."[416]

198. As for OMS' argument that MISO TOs included data points in their risk premium analysis that should not have been considered, the Commission dismissed similar arguments in Opinion No. 531-B by concluding that "whether the regulatory decision involved a settlement agreement or the application of a cost of equity that was calculated in the past, e.g., the 12.38 percent ROE established for the MISO region, does not affect

---

[414] *See* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 98.

[415] *Id.* P 99.

[416] *Id.* P 99.

the reliability of a risk premium analysis."[417] Accordingly, we reject OMS' arguments that *ITC Holdings* and other data points should be removed from MISO TOs' risk premium analysis.

199. OMS also proposes revisions to the dates of several data points included in MISO TOs' risk premium analysis. Although we agree with OMS that any necessary corrections should be made, OMS has not demonstrated that its proposed date corrections would materially affect the results of MISO TOs' risk premium analysis.[418] Therefore, we find that these discrepancies do not undermine the usefulness of MISO TOs' risk premium analysis as corroborative evidence.

200. For the reasons stated above, we find that MISO TOs' risk premium analysis is sufficiently reliable to corroborate the results of the DCF analysis in this proceeding. We, therefore, affirm the Presiding Judge's acceptance of the risk premium analysis to be used as corroborative evidence, in determining whether the midpoint of the zone of reasonableness produced by the Commission's DCF analysis provides a return that satisfies the requirements of *Hope* and *Bluefield*.[419]

4. Expected Earnings

201. A comparable earnings analysis is a method of calculating the earnings an investor expects to receive on the book value of a particular stock. The analysis can be either backward looking using the company's historical earnings on book value, as reflected on the company's accounting statements, or forward-looking using estimates of earnings on book value, as reflected in analysts' earnings forecasts for the company.[420] The latter approach is often referred to as an "expected earnings analysis" and is the approach that MISO TOs used in this proceeding. As the Commission explained in Opinion No. 531-B, "returns on book equity help investors determine the opportunity cost of investing in that particular utility instead of other companies of comparable risk" and, as

---

[417] *Id.* P 98. In *ITC Holdings*, the Commission approved the Entergy Operating Companies' use of the 12.38 percent ROE established for the MISO region. *ITC Holdings*, 146 FERC ¶ 61,111 at P 25.

[418] While OMS calculated a risk premium cost of equity of 9.94 percent, OMS' analysis revised dates for several data points *and* removed approximately 15 data points from MISO TOs' risk premium analysis. OMS Brief on Exceptions, Attachment 1.

[419] *See* Initial Decision, 153 FERC ¶ 63,027 at P 258.

[420] *See* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 125.

a result, an expected earnings analysis can be useful for corroborating whether the results produced by the DCF model may have been skewed by the anomalous capital market conditions reflected in the record.[421]

202. MISO TOs' forward-looking expected earnings analysis uses the same proxy group used in their two-step DCF analysis. MISO TOs' witness, Dr. Avera, started with the return on book equity that Value Line forecasts for each proxy company for the period 2017 to 2019.[422] He then multiplied each of those returns by an adjustment factor to determine each utility's average return, rather than its year-end return. After the elimination of one outlier result,[423] Dr. Avera's analysis produced an adjusted ROE range of 7.61 percent to 16.37 percent, with a midpoint value of 11.99 percent. As with the other alternative methodologies accepted herein, this midpoint value exceeds the 9.29 percent midpoint value of the Commission's two-step DCF analysis.[424]

a. <u>Initial Decision</u>

203. The Presiding Judge declined to rely on Dr. Avera's forward-looking expected earnings analysis. While acknowledging that the Commission in Opinion No. 531 relied upon an expected earnings analysis "identical in all material respects" to Dr. Avera's, the Presiding Judge observed that the Commission was not aware of a critique by Dr. Morin—on whose authority the Commission relied in accepting the expected earnings analysis in Opinion No. 531—that such analysis should be based on a sample of unregulated, rather than regulated, companies. Because Dr. Avera's analysis relied on the regulated companies in the proxy group, and because of "Dr. Avera's inability to address [Dr. Morin's] rejection" of the use of regulated companies in an expected earnings analysis, the Presiding Judge elected not to rely on Dr. Avera's analysis.[425]

---

[421] *Id.* PP 128-129.

[422] Ex. MTO-31.

[423] Dr. Avera eliminated Dominion Resources' adjusted return on common equity of 18.38 percent.

[424] *See* Initial Decision, 153 FERC ¶ 63,027 at P 118.

[425] *Id.* P 325.

b. Briefs on Exceptions

204. MISO TOs ask the Commission to reverse the Initial Decision and instead find that the expected earnings analysis provides a useful and probative benchmark for purposes of evaluating DCF results when anomalous capital market conditions justify consideration of alternative estimates of the cost of equity.[426] MISO TOs refer to the Presiding Judge's conclusion that Dr. Avera failed to follow the approach in Dr. Morin's *New Regulatory Finance*.[427]

205. MISO TOs assert that Dr. Avera's study was the same analysis submitted and accepted in Opinion No. 531 and, although the Presiding Judge argues that the Commission was not aware of Dr. Morin's statement that proxy groups should be made up of unregulated companies, the record in neither proceeding supports this inference.[428] MISO TOs assert that *New Regulatory Finance* does not mandate exclusive reliance on unregulated companies.[429] MISO TOs argue that Dr. Morin's critique of using regulated companies relates entirely to the application of the comparable earnings approach using historical data, which reflects in part past actions of other regulators and historical conditions. MISO TOs argue that this is distinct from the forward-looking expected earnings approach relied upon by the Commission in Opinion No. 531, which MISO TOs contend is no more susceptible to concerns over regulatory influence than the analysts' EPS growth rates that are used to apply the DCF model.[430]

206. MISO TOs argue that the critical inquiry for assessing the merits of an expected earnings analysis is whether the studied companies are of comparable risk to the utilities whose rates are at issue, not whether they are regulated.[431] MISO TOs further state that, although Dr. Avera conceded that expected earnings of non-regulated companies may also provide a logical benchmark for evaluating a just and reasonable ROE, this does not

---

[426] MISO TOs Brief on Exceptions at 2.

[427] *Id.* at 24 (citing Initial Decision, 153 FERC ¶ 63,027 at P 323).

[428] *Id.* at 25 (citing Initial Decision, 153 FERC ¶ 63,027 at P 323).

[429] *Id.* (citing Roger A. Morin, *New Regulatory Finance* 381 (Public Utilities Reports, Inc. 2006) (stating that "[t]he reference group is usually made up of unregulated industrial companies.")).

[430] *Id.* at 25-26.

[431] *Id.* at 26.

preclude consideration of other electric utilities' expected earnings. MISO TOs argue that *Principles of Public Utilities Rates* supports Dr. Avera's assertion that an analysis of comparable earnings may be conducted for "utilities or nonregulated firms."[432]

207. Finally, MISO TOs argue that the Presiding Judge failed to credit Dr. Avera's testimony regarding the use of the expected earnings model by the Virginia State Corporation Commission (Virginia Commission), which is required by statute to consider the earned returns on book value of electric utilities in its region and has established allowed ROEs based on earned returns on book value for peer groups of other electric utilities.[433] MISO TOs argue that Dr. Avera's point was to show that regulators do not consider the expected earning analysis to be useful only when applied to unregulated enterprises and that there is no reason to assume that the Virginia Commission's rationale for its practice is different than the rationale offered by Dr. Avera and Mr. Bonbright – that an expected earnings study of comparable enterprises can provide useful estimates of investor expectations.[434]

c. <u>Briefs Opposing Exceptions</u>

208. Complainants and other parties contend that the Commission should affirm the Presiding Judge's rejection of Dr. Avera's expected earnings analysis.[435] Complainants point out that Dr. Avera's methodology departs from Dr. Morin's prescribed method of composing a proxy group by using a group of electric utilities, rather than a group of unregulated companies.[436] Complainants argue that Dr. Avera was unable to justify this

[432] *Id.* (citing James C. Bonbright *et al.,* Principles of Public Utility Rates 329 (2d ed. 2006)).

[433] MISO TOs Brief on Exceptions at 27.

[434] *Id.*

[435] Complainants Brief Opposing Exceptions at 7-11; Trial Staff Brief Opposing Exceptions at 9-16; Iowa Group Brief Opposing Exceptions at 11-16; Joint Customer Intervenors Brief Opposing Exceptions at 8-17; OMS/Joint Consumer Advocates Brief Opposing Exceptions at 21-24.

[436] Complainants Brief Opposing Exceptions at 7 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 315-316, 323).

departure from Dr. Morin's expected earnings methodology such that their arguments should be rejected.[437]

209. Complainants assert that MISO TOs' arguments that the Commission was aware of Dr. Morin's statement that proxy group should be made up of unregulated companies are unpersuasive and made up of circumstantial evidence.[438] Complainants also disagree with MISO TOs' argument that this departure from Dr. Morin's expected earnings approach is permissible given the Commission's recognition of Dr. Morin as an authority on the expected earnings analysis.[439] According to Complainants, the record in this proceeding is lacking evidence that justifies such a departure. Complainants state that a plain reading of Opinion No. 531 demonstrates that the Commission was unaware of the proxy group flaw in the expected earnings analysis. Complainants assert that Dr. Avera's expected earnings results in circular ratemaking,[440] problems of which the Commission has recognized.[441]

210. Complainants contend that the Presiding Judge's rejection of Dr. Avera's expected earnings analysis was based on the record in this proceeding and represents reasoned decision making. According to Complainants, the Presiding Judge's rejection of Dr. Avera's expected earnings analysis does not affect the Presiding Judge's ultimate ROE recommendation and, by taking exception, MISO TOs are seeking what is effectively an inappropriate advisory opinion from the Commission.[442]

211. Complainants disagree with MISO TOs' argument regarding the Virginia Commission's use of a similar expected earnings methodology.[443]

---

[437] *Id.* at 8.

[438] *Id.* (citing MISO TOs Brief on Exceptions at 25-26).

[439] *Id.* at 8-9 (citing Initial Decision, 153 FERC ¶ 63,027 at P 315).

[440] *Id.* at 9 (citing Exh. S-1 at 97-98).

[441] *Id.* (citing *Minnesota Power and Light Co.*, Opinion No. 12, 3 FERC ¶ 61,045, at 61,132 (1978)).

[442] *Id.* at 9-10.

[443] *Id.* at 10 (citing MISO TOs Brief on Exceptions at 27).

Complainants assert that a mere description of a state Commission's purported use of this method is not sufficient to justify Dr. Avera's departure from Dr. Morin's guidance.[444]

212. Complainants also argue that the record demonstrates other flaws in Dr. Avera's expected earnings analysis. Complainants state that the non-regulated assets of MISO TOs can affect the expected return on their consolidated operations. Complainants also state that the earned return on book equity does not describe the return investors currently require to make an investment in the National Proxy Group of companies and, therefore, it does not establish what the current market cost of equity is for these companies.[445] Complainants note that, in addition to Mr. Gorman, the following witnesses testified that Dr. Avera's expected earnings study is fundamentally flawed and consequently produces unreliable results: Mr. Hill, Iowa Group's witness Mr. Parcel, Mr. Solomon, and Mr. Keyton.[446]

213. Trial Staff notes that the Presiding Judge relied on Mr. Keyton's observations that both the Commission, in Opinion Nos. 531 and 531-B, and Dr. Avera, in his testimony, referred extensively to Roger Morin's *New Regulatory Finance*.[447] Trial Staff argues, however, that Dr. Avera failed to follow the specific three step methodology outlined by Dr. Morin, and instead repeated the type of expected earnings analysis that he used in the Opinion No. 531 proceeding.[448]

214. Trial Staff objects to the use of utility book rates of return as data inputs for an expected earnings study, and asserts that doing so introduces an element of circularity into the analytical process. Trial Staff states that limiting the data field to regulated utilities perpetuates established allowed ROEs rather than estimating the current market costs of equity.[449] Despite MISO TOs' argument that circularity concerns have been

[444] *Id.* at 10 (citing Initial Decision, 153 FERC ¶ 63,027 at P 321).

[445] *Id.* at 10-11 (citing Exh. JC-9 at P 17).

[446] *Id.* at 11.

[447] Trial Staff Brief Opposing Exceptions at 10 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 315-323).

[448] *Id.* (citing Roger A. Morin, *New Regulatory Finance* 383 (Public Utilities Reports, Inc. 2006)).

[449] *Id.* at 11 (citing Exh. S-1 at 98).

obviated by Dr. Avera's use of projected Value Line rates of return on book equity,[450] Trial Staff contends that Dr. Avera's use of projected book rates of return intensifies rather than ameliorates the noted defect. Trial Staff states that if utilities are awarded an ROE on the basis of what Value Line expects them to earn, there is a clear likelihood that they will converge in the future.[451]

215. According to Trial Staff, Dr. Avera used the Value Line data for the period from 2017 to 2019 when shorter-term projections were also available.[452] Trial Staff argues that, given that the expected accuracy of predictive estimates decline as their temporal horizon increases, it would have been preferable for Dr. Avera to average the three available Value Line earned rate of return projections instead of relying solely on the most distant one.[453]

216. Trial Staff disagrees with MISO TOs' contention that the methodology used by Dr. Avera is analytically identical to the one the Commission accepted in Opinion No. 531. Trial Staff acknowledges that, in Opinion No. 531, the Commission cited Dr. Morin's treatise in support of use of this methodology as a check on DCF results.[454] However, according to Trial Staff, the general discussion of this issue in Opinion No. 531 can hardly be read as an endorsement of the particular calculations performed by Dr. Avera on the data he selected for his study. Trial Staff argues that, as with the case of the Commission's inadvertent use of Dr. Avera's dividend yield calculation in Opinion No. 531, the Commission cannot be held to have approved an expected earnings methodology that it had not substantively examined.[455]

217. Regarding MISO TOs' contention that other authorities, such as the Virginia Commission, find comparable earnings studies relying on regulated utility data to be acceptable, Trial Staff states that MISO TOs do not attempt to defend or even explain the

[450] *Id.* at 14 (citing MISO TOs Brief on Exceptions at 25-26 (noting that Dr. Morin generally discusses the use of historical data in his discussion of the comparable earnings methodology)).

[451] *Id.* at 14.

[452] *Id.* at 11-12 (citing Exh. S-1 at 100-101).

[453] *Id.* at 12 (citing Exh. S-1 at 100-101).

[454] *Id.* at 13 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 147).

[455] *Id.* at 13-14.

rationale underlying that choice.[456] Furthermore, Trial Staff states that the Commission has expressly ruled on this issue, indicating its preference for the use of nonregulated firms in conducting a comparative earnings analysis.[457] Trial Staff asserts that neither Dr. Avera nor MISO TOs' brief on exception explain the rationale for the Virginia Commission's ROE determinations.[458]

218. Iowa Group asserts that an expected earnings analysis on regulated utilities produces a rate-making circularity that perpetuates allowed returns on equity rather than measuring the actual cost of capital. Iowa Group asserts that the authorities cited by MISO TOs each recognize and discuss this limitation.[459]

219. According to Iowa Group, the purpose of regulation is to produce the same result that would occur in an unregulated market and, therefore, focusing on regulated returns does not produce a reliable measure of the cost of equity for an unregulated firm.[460] Iowa Group states that conducting an expected earnings analysis based on a proxy group consisting solely of regulated utilities involves allowed returns on equity and requires setting a utility's return based on other utilities' returns. Iowa Group, therefore, states that a utility-based expected earnings study will reflect a regulated marketplace over time and that such a result is contrary to one of the fundamental economic principles of utility regulation. Iowa Group asserts that a historical versus forward-looking distinction is meaningless in this context, since both rely on regulated returns. [461]

220. Joint Customer Intervenors assert that Dr. Avera's expected earnings analysis was invalid because it was applied to regulated utilities, while his primary authority, *New Regulatory Finance*, states that the comparable earnings approach should only be

---

[456] *Id.* at 15.

[457] *Id.* at 15 (citing Opinion No. 12, 3 FERC at 61,132).

[458] *Id.* at 15 (citing Initial Decision, 153 FERC ¶ 63,027 at P 321.

[459] Iowa Group Brief Opposing Exceptions at 14-15 (citing James C. Bonbright, Principles of Public Utility Rates 329-330 (Public Utilities Reports, Inc. 2006); Roger A. Morin, *New Regulatory Finance* 383 (Public Utilities Reports, Inc. 2006); David C. Parcell, The Cost of Capital: A Practitioner's Guide 118-119 (2010)).

[460] *Id.* at 14.

[461] *Id.* at 16.

applied to a comparable risk group of unregulated companies.[462] Joint Customer Intervenors contend that MISO TOs cannot be permitted to rely on a source as a standard for analysis and then disregard that source at will.[463]

221. Joint Customer Intervenors object to MISO TOs' citation to *Principles of Public Utility Rates*, arguing that MISO TOs cite to this source for the first time in their brief on exceptions. Joint Customer Intervenors also note that MISO TOs omitted statements in *Principles of Public Utility Rates* that suggest that the issue of circularity is raised if the comparable earnings approach is applied to regulated utilities.[464]

222. Joint Customer Intervenors contend that MISO TOs' argument is anecdotal and without explanation for why or how the Virginia Commission applied its approach. Joint Customer Intervenors assert that MISO TOs failed to justify departure from the methodology that both Dr. Avera and the Commission have cited as the principal authority on the expected earnings model.[465]

223. In response to MISO TOs' argument that Opinion No. 531's cite to *New Regulatory Finance* demonstrates that the Commission was aware of Dr. Morin's prohibition on the use of regulated utilities in the expected earnings analysis, Joint Customer Intervenors assert that the prohibition was not discovered or brought to the Commission's attention in that proceeding.[466]

224. Joint Customer Intervenors assert that MISO TOs' reference to Dr. Morin's statement that "[t]he reference group is *usually* made up of unregulated industrial companies" is without context, does nothing to refute Dr. Morin's conclusion and

---

[462] Joint Customer Intervenors Brief Opposing Exceptions at 9-10 (citing Dr. Roger A. Morin, *New Regulatory Finance* 381-382 (Public Utilities Reports, Inc. 2006); Initial Decision, 153 FERC ¶ 63,027 at P 316).

[463] *Id.* at 13.

[464] *Id.* at 11 (citing MISO TOs Brief on Exceptions at 26; James C. Bonbright, Principles of Public Utility Rates 239-330 (Public Utilities Reports, Inc. 2006)).

[465] *Id.* at 12.

[466] *Id.* at 13-14 (citing MISO TOs Brief on Exceptions at 25).

rationale for excluding regulated utilities, and fails to recognize the multiple additional instances where Dr. Morin cautions against the use of regulated utilities.[467]

225. Joint Customer Intervenors assert that MISO TOs' claim that Dr. Morin's prohibition on the use of regulated utilities does not apply to forward-looking analyses amounts to a conclusory statement. Joint Customer Intervenors argue that this claim is refuted by Dr. Morin's recognition of the use of the projected comparable earnings approach, and by the absence of any statement by Dr. Morin that the projected comparable earnings approach ameliorates the issue of circularity.[468]

226. Joint Customer Intervenors note that Mr. Solomon explained that Dr. Avera's expected earnings analysis was not based on market data, but on projected returns on book equity, and that the Commission has historically rejected the comparable earnings method.[469] According to Joint Customer Intervenors, the Commission has recognized that the allowed rate of return shall be set "at the rate of return investors require on their investment" and that "when the price-to-book ratio is greater than one, the rate of return investors expect to earn on common equity is greater than the rate of return investors require from their investment in common stock."[470] Joint Customer Intervenors note that Dr. Avera's expected earnings analysis shows a midpoint of 11.44 percent and that the average price-to-book ratio for the proxy group is 1.79.[471]

227. Joint Customer Intervenors assert that an investor willing to pay more than the book value for a utility's expected earnings expects to earn something less than the expected earned rate of return on book value on that investment. Joint Customer Intervenors contend that the range for investors' required ROE should be bracketed by the-earnings-to-price ratio and the expected earned rate on return on book value. Joint

---

[467] *Id.* at 14 (citing MISO TOs Brief on Exceptions at 25 & n.67; Dr. Roger A. Morin, *New Regulatory Finance* 381-382 (Public Utilities Reports, Inc. 2006)).

[468] *Id.* at 14-15 (citing MISO TOs Brief on Exceptions at 26; Dr. Roger A. Morin, *New Regulatory Finance* 385 (Public Utilities Reports, Inc. 2006)).

[469] *Id.* at 15 (citing Exh. JCI-4 at 49:14-20).

[470] *Id.* at 15 (citing *Orange and Rockland Utilities, Inc.*, 44 FERC ¶ 61,253, at 61,952 (1988) (*Orange and Rockland*)).

[471] *Id.* at 16 (citing Exh. JCI-4 at 50:14-17).

Customer Intervenors assert that the midpoint of that range is below the 9.29 percent midpoint of the Presiding Judge's DCF range.[472]

228. OMS/Joint Consumer Advocates state that Dr. Avera's inclusion of regulated utilities in his expected earnings sample group creates an inescapable circularity. According to OMS/Joint Consumer Advocates, a regulatory commission's actions necessarily will affect a utility's future earnings, a forecast of which, in turn, then becomes a factor in establishing the ROE in the next regulatory decision, which itself will then affect future earnings and forecasts thereof. OMS/Joint Consumer Advocates state that excluding regulated utilities from the sample group, as indicated to be necessary by the very source on which Dr. Avera relied,[473] is essential if such circularity is to be avoided.[474]

229. OMS/Joint Consumer Advocates state that MISO TOs give no indication in their brief on exceptions that the base ROE adopted in the Initial Decision would be any different had Dr. Avera's expected earnings study been accepted, nor would any such claim be plausible. OMS/Joint Consumer Advocates state that MISO TOs, therefore, seek nothing more than a request for Commission guidance about how the expected earnings method should be applied in other proceedings in the future. OMS/Joint Consumer Advocates contend that there are other avenues, more appropriate for the task, for obtaining generic guidance of that sort from the Commission.[475]

d. <u>Commission Determination</u>

230. We reverse the Presiding Judge's rejection of MISO TOs' expected earnings analysis. Complainants and Complainant-aligned parties assert that MISO TOs' expected earnings analysis is flawed for a variety of reasons. As discussed in more detail below, we disagree with these assertions and find that the results of MISO TOs' expected

---

[472] *Id.* at 16-17.

[473] OMS/Joint Consumer Advocates Brief Opposing Exceptions at 22 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 315, 320, and 323).

[474] *Id.* (citing Opinion No. 12, 3 FERC at 61,132 (stating that "while the comparative earnings technique can be helpful in determining whether an allowed rate of return is commensurate with the return on investments in other enterprises, if the comparison is only with regulated companies, there is a certain circularity.")).

[475] *Id.* at 23.

earnings analysis corroborates our determination that MISO TOs should be awarded an ROE above the midpoint of the zone of reasonableness produced by the DCF analysis.[476]

231. The Presiding Judge's rejection of MISO TOs' expected earnings analysis relies on the premise that Dr. Morin's guidance in *New Regulatory Finance* precludes the inclusion of regulated companies in expected earnings proxy groups.[477] MISO TOs argue that *New Regulatory Finance* does not mandate exclusive reliance on unregulated companies in forward-looking expected earnings analyses. We agree. In particular, we note that that conclusion is consistent with Dr. Morin's analysis in *New Regulatory Finance*:

> In defining a population of comparable-risk companies, care must be taken not to include other utilities in the sample, since the rate of return on other utilities depends on the allowed rate of return. The *historical* book return on equity for regulated firms is not determined by competitive forces but instead reflects the *past* actions of regulatory commissions. It would be circular to set a fair return based on the *past* actions of other regulators, much like observing a series of duplicative images in multiple mirrors. The rates of return earned by other regulated utilities may well have been reasonable under historical conditions, but they are still subject to tests of reasonableness under current and prospective conditions.[478]

Dr. Morin's recommendation to avoid other utilities in the sample is based on his concern that the use of historical book ROE would be based on past actions of regulatory commissions and, therefore, reliance on those past actions to set an ROE would raise issues of circularity. However, MISO TOs' expected earnings analysis is forward-looking and based on Value Line forecasts, adjusted to reflect each utility's average return.[479] As the Commission explained in Opinion No. 531-B, an expected earnings analysis, in contrast to a comparable earnings

---

[476] Our analysis below does not rely on the arguments regarding the Virginia Commission's use of expected earnings analyses; therefore, we dismiss such arguments as moot.

[477] *See* Initial Decision, 153 FERC ¶ 63,027 at P 323.

[478] Dr. Roger A. Morin, *New Regulatory Finance* 383 (Public Utilities Reports, Inc. 2006) (Emphasis supplied).

[479] *See* Initial Decision, 153 FERC ¶ 63,027 at P 314.

analysis, is sound when it is forward-looking and based on a reliable source of earnings data.[480]

232. Moreover, while Complainants and Complainant-aligned parties refer to various other excerpts from Dr. Morin's *New Regulatory Finance*, each appears to refer to comparable earnings analyses that are based on historical earnings on book value.[481] Thus, even if the Commission did not consider Dr. Morin's statement that proxy groups for comparable earnings analyses should be made up of unregulated companies, that statement alone does not invalidate MISO TOs' expected earnings analysis.

233. We disagree with Complainant-aligned parties' assertions that MISO TOs' expected earnings analysis will nevertheless raise issues of circularity or lead to the convergence of Commission-approved ROEs and the Value Line projections. MISO TOs' zone of reasonableness, in which Commission-approved ROEs are placed, is established by the results of the DCF study. The expected earnings analysis, like the other alternative methodologies accepted herein, is merely used as corroborative evidence. Therefore, we are not persuaded that our acceptance of the expected earnings analysis, which at most can corroborate the Commission's decision to place an ROE above the midpoint of the zone of reasonableness, will raise issues of circularity or lead to a convergence of Commission-approved ROEs to the Value Line projections.

234. We also disagree with Complainants' contention that MISO TOs' expected earnings analysis is flawed because the return on book value does not establish the current market cost of equity for proxy group companies.[482] As the Commission explained in Opinion No. 531-B, investors rely upon the return on book equity to determine the opportunity cost of investing in a particular company, and investors rely upon expected earnings analysis for this purpose without attempting to convert that

---

[480] Opinion No. 531-B, 150 FERC ¶ 61,165 at PP 125-126. *See, e.g.*, *Southern California Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070, at 61,263 (2000) (finding it necessary to adjust Value Line's forecasted returns on book equity to reflect average returns rather than year-end returns); *see also* Roger A. Morin, *New Regulatory Finance* 305-306 (Public Utilities Reports, Inc. 2006).

[481] *See, e.g.*, Dr. Roger A. Morin, *New Regulatory Finance* 382 (Public Utilities Reports, Inc. 2006) (providing the three steps required to implement a comparable earnings analysis).

[482] This appears to be another way of saying that MISO TOs' expected earnings analysis did not consider market-to-book ratios.

opportunity cost into the current market cost of equity.[483] Therefore, consistent with Opinion No. 531-B, we find MISO TOs' expected earnings analysis reliable as corroborative evidence in this proceeding, notwithstanding the lack of a market-to-book adjustment in their analysis. Furthermore, even assuming *arguendo* that a market-to-book adjustment was appropriate, we are not persuaded that Joint Customer Intervenors' approach would accurately estimate the utility's market cost of equity.[484]

235. We also disagree with Joint Customer Intervenors' reliance on *Orange & Rockland* in crafting their argument that the expected earnings analysis cannot be relied upon because the market-to-book ratio of the proxy group exceeds one.[485] As the Commission explained in Opinion No. 531-B, *Orange & Rockland* did not involve a comparable earnings analysis; it involved a proposal to alter the DCF model by adjusting the dividend yield to reflect the expected earnings of the company whose rates were at issue in that proceeding.[486] MISO TOs do not make such a proposal. Instead, MISO TOs have submitted an expected earnings analysis based on their national proxy group of utilities with comparable risk profiles to MISO TOs. Therefore, unlike *Orange & Rockland*, where the Commission rejected a proposal that would have had the effect of setting the base ROE at the company's own expected ROE, MISO TOs' expected earnings analysis is only relevant to the determination of whether the midpoint of the DCF-produced zone of reasonableness provides a market cost of equity sufficient to meet the requirements of *Hope* and *Bluefield*.[487] The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's market cost of equity, because those returns on book equity help investors determine the opportunity cost of investing in that particular utility instead of other companies of comparable risk. Such a calculation is consistent with the requirement in *Hope* that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[488]

---

[483] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 132.

[484] *See* Joint Customer Intervenors Brief Opposing Exceptions at 16.

[485] *Id.* at 15 (citing *Orange and Rockland*, 44 FERC ¶ 61,253 at 61,952 (*Orange and Rockland*)).

[486] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 127.

[487] *Id.* P 128.

[488] *Hope*, 320 U.S. at 603; *see also Petal Gas Storage, L.L.C.*, 496 F.3d 695

(continued...)

236. As the Commission explained in Opinion No. 531-B,[489] investors rely on both the market cost of equity and the book return on equity in determining whether to invest in a utility, because investors are concerned with both the return the regulator will allow the utility to earn *and* the company's ability to actually earn that return. If, all else being equal, the regulator sets a utility's ROE so that the utility does not have the opportunity to earn a return on its book value comparable to the amount that investors expect that other utilities of comparable risk will earn on their book equity, the utility will not be able to provide investors the return they require to invest in that utility. Thus, all else being equal, an investor is more likely to invest in a utility that it expects will have the opportunity to earn a comparable amount on its book equity as other enterprises of comparable risk are expected to earn. Because investors rely on expected earnings analyses to help estimate the opportunity cost of investing in a particular utility, we find this type of analysis useful in corroborating whether the results produced by the DCF model may have been skewed by the anomalous capital market conditions reflected in the record.

237. We are also not persuaded by Trial Staff's assertion that MISO TOs should have also considered shorter term Value Line projections than the 2017-2019 projects they used. While Trial Staff asserts that shorter term projections were available to MISO TOs, it is unclear if those shorter term projections would have resulted in materially different results. Therefore, we are not persuaded that MISO TOs' reliance on Value Line projections for 2017-2019 undermined the usefulness of MISO TOs' expected earnings analysis as corroborative evidence.

238. We also reject the arguments that MISO TOs' exception to the Presiding Judge's rejection of their expected earnings analysis has no relevance on this proceeding and is effectively an attempt to receive general guidance from the Commission. While it is true that, despite his rejection of MISO TOs' expected earnings analysis, the Presiding Judge elected to set the ROE at the upper midpoint of the DCF-produced zone of reasonableness, the placement of the ROE was disputed by Complainants and Complainant-aligned parties in their briefs on exceptions. Given that the expected earnings analysis can further corroborate our finding that a mechanical application of the DCF methodology does not satisfy *Hope* and *Bluefield*, MISO TOs' exception to the Presiding Judge's rejection of their expected earnings analysis is appropriate.

(D.C. Cir. 2007).

[489] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 129.

239. For the reasons stated above, we reverse the Presiding Judge's rejection of MISO TOs' expected earnings analysis.[490] We find that MISO TOs' expected earnings analysis is sufficiently reliable to be used as corroborative evidence that the midpoint of the zone of reasonableness produced by the mechanical application of the DCF methodology does not result in a return that satisfies the requirements of *Hope* and *Bluefield*.

5. State ROEs

240. MISO TOs' witness, Ms. Lapson, presented evidence that all state-authorized ROEs during the period April 1, 2013 through March 31, 2015 for integrated electric utilities providing generation, transmission, and distribution services ranged from 9.5 percent to 10.4 percent.[491] In addition, 87.34 percent of state-authorized ROEs for both integrated electric utilities and distribution-only electric utilities during that period were within this range. Ms. Lapson also testified that investing in Commission-regulated electric transmission involves significant risks that investment in other utilities does not and that setting MISO TOs' ROE at a level generally below state-authorized ROEs will make investment in interstate electric transmission less attractive than investment in conventional electric utility activities.

a. Initial Decision

241. The Presiding Judge determined that the state-authorized ROEs in the record support setting MISO TOs' base ROE above the midpoint of the DCF zone of reasonableness. The Presiding Judge observed that the midpoint of the DCF zone of reasonableness is lower than all of the state-authorized ROEs for integrated electric utilities and two-thirds of the state-authorized ROEs for distribution-only utilities. The Presiding Judge noted that MISO TOs face risks that are at least as great as the risks facing both categories of companies.[492] The Presiding Judge rejected arguments regarding the data used to identify the state-authorized ROEs, noting that, consistent with Opinion Nos. 531 and 531-B, this data reflected the most recent data in the record.[493] The Presiding Judge also rejected the argument that the 50 basis point incentive ROE adder should be considered in setting the base ROE, noting that the Commission flatly

---

[490] *See* Initial Decision, 153 FERC ¶ 63,027 at P 323.

[491] Exh. MTO-42 at 1-2.

[492] Initial Decision, 153 FERC ¶ 63,027 at PP 454-456.

[493] *Id.* PP 366-367.

rejected this argument in Opinion No. 531.[494] Finally, the Presiding Judge rejected a host of arguments contending that differences in the risk profile of the state-regulated utilities rendered base ROE comparisons inapt.

b. <u>Briefs on Exceptions</u>

242. OMS states that the Presiding Judge interpreted Opinion No. 531-B as requiring that he give more weight to the fact that the average state-authorized ROE exceeded the DCF midpoint than to the demonstrated downward trajectory in state-authorized ROEs.[495] OMS argues that, in this regard, the Presiding Judge misconstrues Opinion No. 531-B. According to OMS, the Commission did not, in that instance, consider and dismiss a proven downward movement in state ROEs; rather, it simply found that the record lacked proof of such a downward trend.[496] OMS states that the record evidence clearly shows a downturn in state-authorized ROEs over the past decade continuing through the DCF study period. It further contends that the failure of Ms. Lapson's study to account for this trend is a "fatal flaw" that disqualifies the study for use as support for setting the base ROE above the midpoint.[497] Furthermore, OMS contends that the downward trend in state-authorized ROEs should alleviate concerns about capital being shifted away from transmission investments into distribution investments.

243. OMS further argues that, in Opinion No. 531, the Commission compared the investment risks of electric infrastructure with those of electric distribution infrastructure and concluded that the Commission-approved ROE for transmission assets should be higher than the state-authorized ROEs for distribution assets.[498] OMS avers that the basis for this finding was the Commission's determination that investing in transmission carries greater risk than investing in distribution. However, OMS states that Ms. Lapson's analysis is based solely on state-authorized ROEs for integrated utilities, and that Ms. Lapson consciously avoided using data from distribution-only companies.[499]

---

[494] *Id.* P 380.

[495] OMS Brief on Exceptions at 38-39 (citing Initial Decision, 153 FERC ¶ 63,027 at P 363).

[496] *Id.* at 39 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at n.176).

[497] *Id.*

[498] *Id.* at 40 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 149).

[499] *Id.* (citing Exh. MTO-16 at 54:5-14 and OMS Reply Brief at 31).

244. OMS states that the Presiding Judge found that the mean, median, and midpoint of the state-authorized ROEs for distribution-only utilities (9.45 percent, 9.55 percent, and 9.41 percent, respectively) are above the midpoint of the DCF analysis adopted in the Initial Decision (i.e., 9.29 percent).[500] OMS contends, however, that the mean and the midpoint of the state-authorized ROE numbers for distribution-only utilities are below the base ROE of 9.54 percent recommended by Mr. Gorman and that the median is only 0.01 percent above Mr. Gorman's proposed ROE for MISO TOs.[501] OMS states that, to the extent that state-authorized ROEs for distribution-only utilities are a meaningful consideration in setting transmission ROEs, the base ROE proposed by the Complainants in this proceeding is reasonable and sufficient.

245. OMS also asserts that the Commission should reject the Presiding Judge's finding that investing in MISO TOs' Commission-regulated electric transmission entails risks that are at least as great as the risks of investing in the integrated electric utilities analyzed by Ms. Lapson, and therefore it would be illogical to award a base ROE for MISO TOs that is below the state-authorized ROEs of these integrated electric utilities.[502] OMS states that there is no evidence in the record that supports the proposition that the risks assumed by MISO TOs, or by transmission companies in general, are at least as great as those of the integrated utilities studied by Ms. Lapson. On the contrary, OMS states that evidence presented by Mr. Hill indicates that the risks of transmission service are less than the risks of integrated utility operations, which include the risks of competitive operations.[503] Joint Customer Intervenors similarly argue assert that the Presiding Judge failed to consider evidence demonstrating that the formula rate-based transmission service at issue here is less risky than the integrated generation and distribution service regulated by the state commissions.[504]

246. OMS also states that, should the Commission find that MISO TOs are largely or predominantly integrated or that MISO TOs have risks "at least as great" as those of integrated utilities, an upward adjustment from the DCF midpoint based on comparing utilities having similar risk profiles would not be supportable here. OMS reiterates

---

[500] *Id.* at 41 (citing Initial Decision, 153 FERC ¶ 63,027 at P 400).

[501] *Id.* (citing Exh JC-1 at 2:13; Exh. JC-9 at 32:7-8).

[502] *Id.* (citing Initial Decision, 153 FERC ¶ 63,027 at P 453).

[503] *Id.* at 41-42 (citing Exh. JCA-1 at 35:17-22).

[504] Joint Customer Intervenors Brief on Exceptions at 47-48 (citing Exh. JCI-4 at 32:21-36:2).

its Reply Brief argument that an upward adjustment of the base ROE in reliance on Ms. Lapson's state ROE benchmark would not compensate investors by an amount that is in any way linked to the risks that purportedly exceed those associated with distribution companies. Rather, according to OMS, it would simply confer on investors in transmission infrastructure a premium, but one that has no nexus to the risks it is meant to address.[505] OMS states that over-compensating investors for transmission risks is not without its own adverse impacts, including potentially reducing the amount of capital available for other necessary electric infrastructure investments.

247. Joint Customer Intervenors state that the Commission, prior to Opinion No. 531, had long held that wholesale ROE determinations should not be influenced by state-authorized ROEs.[506] Joint Customer Intervenors also argue that incentives should be taken into consideration when comparing the base ROEs awarded to MISO TOs in this proceeding to the state-awarded ROEs. Joint Customer Intervenors assert that it is inappropriate to compare state-awarded ROEs that do not include incentives to Commission-awarded ROEs that do not include incentives.[507]

248. Joint Customer Intervenors explain that Mr. Solomon presented an analysis by SNL Financial that demonstrated that the overwhelming majority of electric utilities are not able to earn their state-awarded ROEs, while MISO TOs' transmission formula rates provide assurance that MISO TOs are able to earn their Commission-awarded ROE. Joint Customer Intervenors state that the utilities in the SNL Financial study earned ROEs that were, on average, 120 basis points below their state-awarded ROEs. Joint Customer Intervenors therefore argue that MISO TOs' ROE should not be compared to state-awarded ROEs but should instead be compared to the ROEs that utilities can reasonably be expected to earn under those state-awarded ROEs.[508]

---

[505] OMS Brief on Exceptions at 42 (citing OMS Reply Brief at 32).

[506] Joint Customer Intervenors Brief on Exceptions at 47 (citing *Middle S. Services, Inc.*, Opinion No. 124, 16 FERC ¶ 61,101, at 61,221 (1981); *Boston Edison Co.*, Opinion No. 411, 77 FERC ¶ 61,272, at 62,172 (1996); *Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC ¶ 61,001, at 61,009 (1996)).

[507] *Id.* at 48-49.

[508] *Id.* at 49-50 (citing Exh. JCI-7 at 110-113).

c. Briefs Opposing Exceptions

249. MISO TOs argue that the Presiding Judge properly credited Ms. Lapson's state ROE evidence and correctly found that wholesale transmission is at least as risky as an integrated electric utility and more risky than a distribution-only electric utility.[509] MISO TOs agree that Ms. Lapson's study supports allowing MISO TOs to collect a base ROE above the midpoint, as the DCF midpoint is lower than all the state-authorized ROEs for integrated utilities and lower than two-thirds of the distribution-only electric utilities' state-authorized ROEs.[510] MISO TOs argue that, given "the clear Commission precedent support consideration of state-authorized" ROEs, the Presiding Judge correctly discredited the arguments made in Joint Customers' and OMS's exceptions, which MISO TOs assert, were previously rejected in Opinion Nos. 531 and 531-B.[511] In particular, MISO TOs contend that the Presiding Judge correctly disregarded arguments that the downward trend in state ROEs undermined the usefulness of Ms. Lapson's evidence. Additionally, MISO TOs argue that it is equally unpersuasive for Joint Customers to argue that the Presiding Judge erred by excluding from consideration any ROE incentives awarded under FPA section 219.[512]

d. Commission Determination

250. We agree with the Presiding Judge that the state-authorized ROE study by Ms. Lapson corroborates the finding that a mechanical application of the DCF methodology does not satisfy *Hope* and *Bluefield*. We do so because the 9.29 percent midpoint calculated by the Presiding Judge's DCF study is lower than all of the state-authorized ROEs of integrated electric utilities and most of the distribution-only utilities in that study and because investing in MISO TOs' Commission-regulated electric transmission entails risks that are "at least as great" as those faced by investors in integrated electric utilities.[513] In Opinion No. 531, the Commission found that record evidence of state commission-approved ROEs supported adjusting the New England transmission owners' base ROE above the midpoint of the zone of reasonableness. In that decision, the Commission stated that it was not "using state commission-approved

---

[509] MISO TOs Brief Opposing Exceptions at 31.

[510] *Id.* at 32.

[511] *Id.* at 32-33 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 353-81).

[512] *Id.* at 33.

[513] Initial Decision, 153 FERC ¶ 63,027 at P 455.

ROEs to establish the . . . ROE" but that the Commission found that "the discrepancy between state ROEs and the . . . midpoint serve[d] as an indicator that an adjustment to the midpoint . . . is necessary to satisfy *Hope* and *Bluefield*."[514] In Opinion No. 531-B, the Commission further explained that "the Commission merely relied on the state commission-authorized ROEs – in conjunction with evidence that interstate transmission is riskier than state-level distribution – as evidence that the . . . midpoint of the . . . zone of reasonableness was insufficient to satisfy . . . *Hope* and *Bluefield*."[515] We find that the rationale employed there justifies our adoption of the Presiding Judge's finding with regard to Ms. Lapson's study.

251. We also find that OMS's and Joint Customer Intervenors' claims about a downward trend in overall state-authorized ROEs from 10.54 percent in 2005 to 9.58 percent during the first six months of 2015, are not enough, in and of themselves, to overcome the fact that the midpoint is below the vast majority of state-authorized ROEs that became effective during the April 1, 2013 through March 31, 2015 period of Ms. Lapson's study.[516] As noted above, the relevance of the study is to examine whether a survey of state-authorized ROEs might support making an upward adjustment to the Commission-allowed ROE. A study demonstrating that the vast majority of state-authorized ROEs studied exceed the midpoint of the zone of reasonableness suggests that the midpoint of that zone may be too low, and the asserted downward trend in state-authorized ROEs does not, in and of itself, counter this suggestion. First, irrespective of any downward trend in overall state commission-approved ROEs, the fact remains that every single state commission-approved ROE for a vertically integrated utility in the April 1, 2013 through March 31, 2015 study period exceeded the midpoint of the Presiding Judge's DCF study, including those in the first three months of 2015. Mr. Gorman's study, which asserted that the average of state-authorized ROEs declined to 9.58 percent during the first six months of 2015, included distribution-only electric utilities, as well as integrated electric utilities.[517] In addition, Mr. Gorman's 9.58 percent figure is still above the 9.29 percent midpoint of the DCF zone of reasonableness. Moreover, Mr. Gorman excluded base ROEs authorized by the Virginia Commission. As the Presiding Judge pointed out, inclusion of the Virginia Commission-authorized ROEs would have raised the average of the state-authorized ROEs approved in the first half of

---

[514] Opinion No. 531, 147 FERC ¶ 61,234 at P 148.

[515] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 84.

[516] Initial Decision, 153 FERC ¶ 63,027 at P 353.

[517] Exh. JC-26 at 1.

2015 to 10.09 percent,[518] 80 basis points above the 9.29 percent midpoint of the DCF zone of reasonableness.

252. We further disagree with OMS that Ms. Lapson's analysis is "based solely on state-authorized ROEs for *integrated* utilities" and that "she consciously avoided using data from distribution-only companies."[519] As the Presiding Judge noted, Ms. Lapson's study includes data from distribution-only utilities.[520] Additionally, OMS makes arguments comparing the mean and midpoint of the state-authorized ROE numbers for distribution-only utilities to the 9.54 percent base ROE recommended by Mr. Gorman. Again, we note that the Ms. Lapson's study's only relevance is to determine whether state-authorized ROEs are higher than the midpoint of the DCF zone of reasonableness. The study does not prescribe where in the zone of reasonableness the base ROE should be established. Ms. Lapson's study clearly indicates that the 9.29 percent midpoint is lower than all of the state-authorized ROEs of integrated electric utilities in the study and lower than two-thirds of all of the state-authorized ROEs of distribution-only electric utilities in the study.[521]

253. We also disagree with arguments that the record does not contain evidence that MISO TOs and other transmission companies face risks that are at least as great as the risks of investing in integrated electric utilities. Ms. Lapson's study contains an extended discussion of the risks faced by MISO TOs and transmission owners in general.[522] For instance, Ms. Lapson explains that developing interstate electric transmission is subject to "controversy and public opposition" and "subject to the requirements of multiple jurisdictions," which can increase project complexity and force transmission developers to "make economic concessions to . . . gain approvals."[523] Furthermore, Ms. Lapson states that transmission-owning utilities face "execution risks in completing the project and the risk that parties may seek to disallow rate recovery of any cost overruns."[524]

---

[518] Initial Decision, 153 FERC ¶ 63,027 at P 370.

[519] OMS Brief on Exceptions at 40.

[520] *See*, *e.g.*, Initial Decision, 153 FERC ¶ 63,027 at PP 338, 401, 402.

[521] Initial Decision, 153 FERC ¶ 63,027 at PP 455-56.

[522] *See id.* PP 340-48.

[523] Exh. MTO-39 at 40:14, 18-22.

[524] *Id.* at 40: 22-24.

Lapson also notes that medium or small utilities, such as "quite a few of the MISO [TOs]" require external funding, a consideration which creates uncertainty associated with capital market conditions and access to the debt and equity markets.[525]

254. Ms. Lapson also asserts that MISO TOs have capital expenditure (capex) commitments higher than most electric utilities and observes that utilities with high capex are exposed to execution or implementation risks associated with large capital investment, risks associated with the fact that "nearly all of the MISO TOs are invested in capex in excess of their internal cash from operations," and risks associated with the need for external financing.[526] Additionally, we note, and agree with, the Presiding Judge's conclusion that "investment in electric transmission poses a number of unique risks that investment in integrated electric utilities does not" and that investment in "MISO TOs' transmission entails additional risks due to the owners' high capex requirements."[527]

255. We also disagree with Joint Customer Intervenors' argument that "failing to consider the incentives included in state-awarded ROEs and then comparing them to FERC-awarded ROEs that do not include incentive adders is inappropriate on its face."[528] Ms. Lapson stated that she removed all incentive adders from the state-authorized ROEs included in her study, and the Presiding Judge found that the other parties had not provided evidence to show that any of the state-authorized ROEs included in her study did include such incentives.[529] It is appropriate to compare state-authorized ROEs that do not include incentive adders with FERC-approved ROEs that also do not include incentive adders, as Ms. Lapson did. As the Commission explained in Opinion No. 531, "[a]lthough section 219 of the FPA gives [the Commission] authority to provide incentives above the base ROE, nothing in section 219 relieves [the Commission] from first setting the base ROE at a place that meets *Hope* and *Bluefield*."[530] Since the base

---

[525] *Id.* at 41:1-6.

[526] Initial Decision, 153 FERC ¶ 63,027 at PP 342-347 (citing Exh. MTO-16 at 40:4-5, 13-15.

[527] Initial Decision, 153 FERC ¶ 63,027 at P 397 (citing Exh. MTO-16 at 35, Table 3, 40:4-19, 41:10-42:12; Moody's Rating Methodology, Regulated Electric and Gas Utilities, December 23, 2013 at 24).

[528] JCI Brief on Exceptions at 49.

[529] Exh. MTO-16 at 52. Initial Decision, 153 FERC ¶ 63,027 at P 374.

[530] Opinion No. 531, 147 FERC ¶ 61,234 at P 153.

ROE must therefore not include incentives, it would be equally inappropriate to compare state-authorized ROE data that includes state-awarded ROE incentives.

256. Joint Customer Intervenors also argue that the Commission should not compare MISO TOs' ROE to state-awarded ROEs, but should instead compare MISO TOs' ROE to the state-awarded ROEs that utilities can expect to actually earn. Again, Ms. Lapson's conclusions serve as one indicator among several suggesting that the 9.29 percent midpoint of the DCF-produced zone of reasonableness is insufficient to satisfy *Hope* and *Bluefield*. That is, these conclusions, along with the other alternative methodologies described above have convinced us to set the base ROE above the midpoint in this proceeding. The survey does not, and should not, serve to prescribe the Commission's placement of the base ROE at any particular point within the zone of reasonableness. Additionally, we find that evidence that Joint Customer Intervenors provide to argue that not all utilities can expect to actually earn the state-authorized ROE they are permitted earn is both incomplete and not wholly supportive of their argument here.[531]

6. Impact of Base ROE on Planned Investment

a. Initial Decision

257. The Presiding Judge concluded that setting MISO TOs' base ROE at the midpoint of the zone of reasonableness "could undermine their ability to attract capital for new investment in electric transmission."[532] The Presiding Judge reviewed the evidence provided by Mr. Kramer, observing, in particular, that the 2014 MISO Transmission Expansion Plan (MTEP) contemplated roughly $20 billion of investment in transmission facilities. The Presiding Judge recounted how Ms. Lapson explained that MISO TOs' ROE was one of their primary sources of cash flow, which they used to fund investment in new transmission facilities.[533] In addition, she noted that this cash flow also helped to demonstrate MISO TOs' financial health to investors. Too large a reduction in base ROE would thus both cut off their cash flow as a significant source of investment capital and make it more difficult for MISO TOs to attract reasonably priced capital. Limited access to capital could, in turn, force MISO TOs to divert investment from projects contemplated in the MTEP and instead toward transmission projects for local reliability, which they are obligated to build.[534] In addition, the Presiding Judge also noted

[531] Exh. JCI-4 at 34:1-12.

[532] Initial Decision, 153 FERC ¶ 63,027 at P 480.

[533] *Id.* PP 465-466.

[534] *Id.* PP 468-469.

Ms. Lapson's observation that a large ROE reduction could create continued uncertainty, reducing investor interest in transmission-owning entities more generally.[535]

258. In reaching those conclusions, the Presiding Judge rejected the argument that the fact that the MISO TOs had not yet cancelled or deferred any transmission projects, even though they expected some reduction in base ROE, demonstrated that an ROE reduction was unlikely to reduce their investment in transmission infrastructure. The Presiding Judge explained that Ms. Lapson's testimony indicated that too large an ROE reduction would impair new investment, not that any reduction whatsoever would have that effect.[536] The Presiding Judge explained that, in Opinion No. 531, the Commission relied on evidence showing that a 175 basis-point reduction in ROE "*could*" reduce transmission investment. The Presiding Judge therefore concluded that Opinion No. 531 was consistent with the conclusion that reducing MISO TOs' base ROE from its current level to the midpoint of the zone of reasonableness, a 310-basis-point reduction, could undermine their ability to attract new capital to invest in transmission infrastructure.[537]

b. <u>Briefs on Exception</u>

259. Joint Customer Intervenors argue that the evidence did not demonstrate a correlation between the ROE and the level of transmission investment. According to Joint Customer Intervenors, Mr. Kramer stated that "he does not know what would have happened" when asked whether the amount of new projects would have exceeded the levels he cited if the Commission had allowed a return higher than the current 12.38 percent ROE.[538] Joint Customer Intervenors also claim that Mr. Kramer was unable to provide "evidence that indicates whether or not the same benefits would or would not have been achieved . . . under the suggested hypothetical of a lower base ROE."[539] Joint Customer Intervenors further argue that Ms. Lapson's statements, while relied upon by the Initial Decision, merely assert that a reduction in ROE would result in a reduction in earnings and cash flow, and that credit ratings might be affected.[540]

---

[535] *Id.* P 471.

[536] *Id.* PP 473-475.

[537] Initial Decision, 153 FERC ¶ 63,027 at PP 476-477.

[538] Joint Customer Intervenors Brief on Exceptions at 52-53 (citing Ex. JCI-14 at 1).

[539] *Id.* at 53 (citing Ex. JCI-13 at 1).

[540] *Id.* at 54 (citing Initial Decision, 153 FERC ¶ 63,027 at PP 463-470).

Joint Customer Intervenors assert that there is no evidence in the record suggesting that their proposed base ROE would do any harm to transmission investment in the MISO region.[541]

c. Briefs Opposing Exception

260. MISO TOs argues that Joint Customers wrongly suggest that the Presiding Judge was required to quantify the precise ROE necessary to sustain transmission investment, as such precision is not required by the FPA.[542] Additionally, MISO TOs argue that the Presiding Judge "cited ample record support" to support his conclusion that setting the DCF at the midpoint of zone of reasonableness would have placed MISO TOs' base ROE below the ROE available for comparable or less risky investments, thereby impairing MISO TOs ability to compete for capital.[543] In particular, they note that the Presiding Judge adequately responded to the contention that federally regulated transmission mission facilities are less risky than those subject to state regulation and, therefore, that the federally regulated entities could still adequately attract capital, even if they are receiving a lower ROE.

d. Commission Determination

261. We affirm the Presiding Judge's conclusion that setting MISO TOs' base ROE at the midpoint of the zone of reasonableness could impair investment in transmission facilities. As the Commission explained in Opinion No. 531, adequate transmission investment supports the Commission's responsibility to ensure that rates are just and reasonable because new transmission facilities help to "promote efficient and competitive electricity markets, reduce costly congestion, enhance reliability, and allow access to new energy resources, including renewables."[544] We continue to find that this is the case, including for the $20 billion of transmission investment contemplated by the 2014 MTEP.[545]

---

[541] *Id.*

[542] MISO TOs Brief Opposing Exceptions at 37.

[543] *Id.*

[544] Opinion No. 531, 147 FERC ¶ 61,234 at P 150.

[545] Initial Decision, 153 FERC ¶ 63,027 at PP 459, 461.

262. We find that reducing MISO TOs ROE to the midpoint of the zone of reasonableness could, as Ms. Lapson and Mr. Kramer explained, put at risk the MTEP investments as well as those in other beneficial transmission facilities. By reducing MISO TOs' cash flow, an overly large ROE reduction will reduce MISO TOs' ability to fund new transmission investment with the profits from their existing operations. In addition, an overly large ROE reduction could cause MISO TOs' credit ratings and/or other measures of financial health to deteriorate, impairing their ability to raise external capital to fund new transmission facilities. In particular, as Ms. Lapson explained, a "radical reduction" in MISO TOs ROE could cause investors to shift their capital to state-regulated utilities, which may have a similar risk to MISO TOs and, as discussed above, may earn an ROE greater than the midpoint of the zone of reasonableness, making them significantly more attractive investments. As she explained, a recent UBS report identified a "perception" that "investors were already beginning to react to the potential for lower [b]ase ROEs by shifting their investment capital to [state-regulated] electric and gas retail distribution investments and away from wholesale electric transmission."[546]

263. We conclude that reducing MISO TOs' ROE to the midpoint of the zone of reasonableness could be sufficient to bring about those results. As the Presiding Judge explained, in Opinion No. 531, the Commission concluded that a 175-basis-point ROE reduction—from an ROE of 11.14 to an ROE of 9.39—could put transmission investment at risk.[547] The same is true here. Based on the evidence in this proceeding, we conclude that a base ROE reduction nearly twice as large as the Commission considered in Opinion No. 531 — that is, a reduction from an ROE of 12.38 to an ROE of 9.29 — is at least as likely to put transmission investment at risk as was the reduction contemplated in Opinion No. 531. Thus, as in Opinion No. 531, we find that the potential for reduced transmission investment counsels against a mechanical application of the DCF.[548]

264. Joint Customer Intervenors' arguments do not require a contrary conclusion. In particular, we note that the Commission has never required a demonstrated correlation between a particular ROE level and a particular level of transmission investment or that a reduction in ROE will cause particular harms to customers within MISO. Further, the Commission, in Opinion No. 531, concluded that evidence that a certain ROE reduction "could" imperil transmission investment militated against imposing such a reduction.[549]

---

[546] *Id.* P 350 (citing Exh. MTO-44).

[547] *Id.* P 479 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 150).

[548] *See* Opinion No. 531, 147 FERC ¶ 61,234 at P 150.

[549] *Id.*

For the reasons discussed, we conclude that the evidence in the record suggests that setting MISO TOs' base ROE at the midpoint of the zone of reasonableness could impair their ability to invest in new transmission infrastructure.

265. Based on the presence of anomalous capital market conditions and informed by the returns indicated by the CAPM, expected earnings, and risk premium analyses discussed above, we find that the ROE for MISO TOs should be above the midpoint of the zone of reasonableness established by the DCF analysis. We now turn to the issue of precisely where in the upper half of the zone of reasonableness to set MISO TOs' ROE.

7. Placement of the Base ROE above the Midpoint

a. Initial Decision

266. The Presiding Judge concluded that the presence of anomalous market conditions justified an ROE above the midpoint of the zone of reasonableness. The Presiding Judge concluded that, consistent with Opinion No. 531, it was appropriate to set the base ROE at the midpoint of the upper half of the zone of reasonableness.[550]

b. Briefs on Exceptions

267. Joint Customer Intervenors contend that, to the extent that capital market conditions were anomalous and such conditions justified a return higher than the midpoint of the zone of reasonableness, the appropriate point would be the 75th percentile of the zone of reasonableness. They state that their witness, Mr. Mr. Solomon testified that the 75th percentile is the point in the zone of reasonableness at which 25 percent of the proxy companies have higher ROEs and 75 percent of the proxy companies have lower ROEs. Joint Customer Intervenors argue that, while the Initial Decision stated that the Commission has thus far selected either the midpoint or the upper midpoint to be the base ROE applicable to multiple transmission owners, there is no Commission policy mandating the choice of the upper midpoint following a decision to choose a point above the midpoint or median.[551] Joint Customer Intervenors note that the Commission has chosen a point other than the midpoint or upper midpoint.[552] Joint Customer Intervenors

---

[550] Initial Decision, 153 FERC ¶ 63,027 at PP 118-119, 491.

[551] Joint Customer Intervenors Brief on Exceptions at 50-51 (citing Initial Decision, 153 FERC ¶ 63,027 at P 118).

[552] *Id.* at 51 (citing *Sw. Pub. Serv. Co.*, Opinion No. 421, 83 FERC ¶ 61,138, at 61,637-38 (1998)).

argue that, even if the Commission had never chosen a point other than the midpoint or upper midpoint, the Commission has never declared that only those two points may be considered and, therefore, other points could be considered.[553]

268. OMS states that, should the Commission find that anomalous market conditions existed during the study period, the Commission need not (and should not) default to placing the Base ROE at the upper midpoint. OMS states that the Commission's charge in cases such as this is to set the new Base ROE at a level sufficient for MISO TOs to attract capital on reasonable terms, but no higher, and that to comply with that mandate, the Commission must have the flexibility to set the Base ROE anywhere between the DCF midpoint and the upper midpoint. OMS notes that, in Opinion No. 531-B, the Commission rejected a proposal to allow a Base ROE at the 75th percentile of the zone of reasonableness on the grounds that Commission precedent supported use of the "central tendency" to determine an appropriate return in cases involving the placement of the Base ROE for a region-wide group of utilities.[554] OMS states that Opinion No. 531-B also rejected arguments that Commission precedent requires the Commission to consider distribution of results within the proxy group when determining where in the upper half of the zone the Base ROE should be placed.[555]

269. OMS contends that the Presiding Judge only evaluated the alternative benchmarks to determine if a higher ROE should be used than the midpoint. OMS argues that the Presiding Judge erred by finding irrelevant the relationship between the ROE values from the alternative benchmarks and the upper midpoint, which would support a value lower than the upper midpoint.[556]

270. OMS argues that the Commission should not bind itself to an "either-or" choice between the DCF midpoint and the Upper Midpoint; rather, it must be able to set the Base ROE at other points of central tendency within the upper-half of the zone of reasonableness, such as the mean or the median of the upper-half of the zone. OMS states that the Commission could also set the Base ROE at any point of central tendency within a range between the midpoint of the DCF zone of reasonableness and the Upper Midpoint (i.e. between 9.29 percent and 10.32 percent). OMS argues that the

---

[553] *Id.*

[554] OMS Brief on Exceptions at 28 (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 55).

[555] *Id.* (citing Opinion No. 531-B, 150 FERC ¶ 61,165 at P 55).

[556] *Id.* at 9.

Commission should take care to preserve maximum flexibility in establishing the new base ROE for MISO TOs, and reject the notion that it is limited to a binary choice between the DCF midpoint and the upper midpoint, where capital market conditions have been proven "anomalous."[557]

271. Complainants contend that the Initial Decision erred in failing to consider their proposed four quartile approach for placement of the ROE.[558] Complainants state that, even though the Commission typically considers the midpoint to be the best embodiment of the central tendency within the zone of reasonableness for the base ROE for multiple utilities, the Commission has expressed concern that this approach gives undue weight to the two extreme values in that range.[559] Complainants state that, to mitigate this shortcoming, Mr. Gorman separated the DCF estimates within his original zone of reasonableness (i.e., 6.75 to 11.01 percent) into four quartiles and redefined the upper and lower bounds of the zone by using the medians of the upper and lower quartiles, resulting in a zone of reasonableness from 8.60 to 9.56 percent. Mr. Gorman then recommended a base ROE situated at the 9.08 percent midpoint between these outer bounds, which he recommended for MISO TOs that have common equity ratios of 55 percent or less.[560] Complainants contend that this approach is appropriate because of the distortive effect of the extreme values, as demonstrated by the effect of their removal.[561]

c. <u>Briefs Opposing Exceptions</u>

272. MISO TOs argue that the placement of the new base ROE at the upper half midpoint is consistent with Opinion No. 531 and produces reasonable results supported by alternative benchmarks and state ROEs.[562] In support of this argument, MISO TOs

---

[557] *Id.* at 29.

[558] Complainants Brief on Exceptions at 23 (citing Complainants Initial Brief at 40-43; *see also* Complainants Reply Brief at 28-29).

[559] *Id*. (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 144 (citing *S. Cal. Edison Co*., 131 FERC ¶ 61,020, at P 91 (2010), *remanded on other grounds sub. nom. S. Cal. Edison Co. v. FERC*, 717 F.3d. 177 (D.C. Cir. Ct. 2013) and *S. Cal. Edison Co*., 131 FERC ¶ 61,020 at P 86 (citing *Northwest Pipeline Corp.,* 99 FERC ¶ 61,305 at 62,276 (2002)).

[560] *Id*. at 24 (citing Ex. JC-1, pp. 33-37; *see also* Ex. JC-22, pp. 18-19).

[561] *Id*. at 24-25.

[562] MISO TOs Brief Opposing Exceptions at 19.

argue that nothing in Opinion Nos. 531 or 531-B requires the Presiding Judge to calibrate the precise increment by which the DCF midpoint is affected by anomalous capital market conditions and such "exactitude is neither practical nor necessary to satisfy" the FPA.[563] MISO TOs note that the Presiding Judge relied on Opinion No. 531 to inform his zonal placement because this precedent represents the Commission's "most current explication of its approach to zonal placement," and the issues decided in Opinion No. 531 "were substantively identical" to the questions at issue here.[564]

273. MISO TOs argue that, while in deviating from midpoint values in the past, the Commission has typically relied upon comparative risk assessment, this fact does not preclude consideration of ROE adjustments based on other factors, including demonstrated infirmities in DCF inputs and results.[565] MISO TOs also argue that there is no requirement that the Presiding Judge examine every conceivable zonal point within the DCF range or quantify the exact basis-point impact of the documented capital market anomalies. They further argue that the upper-half midpoint is "consistent with the Commission's preference for the central tendency."[566]

274. MISO TOs also state that the Presiding Judge did not need to explicate his reasons for not adopting Complainants' quartile approach, because such approach is "arbitrary and contrived merely to constrict the zone of reasonableness."[567] Additionally, they state that Mr. Gorman articulated the rationale for his proposal and the Presiding Judge rightly rejected this approach.[568]

d. <u>Commission Determination</u>

275. In the Initial Decision, the Presiding Judge determined that, consistent with Commission precedent, in the presence of anomalous capital market conditions, the base ROE should be established at the upper midpoint of the zone of reasonableness. The Presiding Judge stated that, when determining the base ROE applicable to multiple

---

[563] *Id.* at 20.

[564] *Id.* at 21.

[565] *Id.* at 21.

[566] *Id.* at 22 (citing Initial Decision at P 118).

[567] *Id.* n.50.

[568] MISO TOs Brief Opposing Exceptions at n.50.

transmission owners, "the only two places within the zone of reasonableness that have thus far proved consistent with the Commission's preference of the central tendency" are the midpoint and upper midpoint, which the Presiding Judge determined to be 9.29 percent and 10.32 percent, respectively.[569] In this proceeding, we adopt the Presiding Judge's finding that the upper midpoint of the zone of reasonableness represents the just and reasonable base ROE for the MISO transmission owners.

276. We are unpersuaded by contentions that, if the Commission concludes that MISO TOs' base ROE should be set above the midpoint of the zone of reasonableness, the base ROE should be placed at the true 75th percentile of the zone of reasonableness, rather than at the 10.32 percent midpoint of the upper half of the zone. As the Commission explained in Opinion No. 531-B,[570] the Commission has traditionally used measures of central tendency to determine an appropriate return in ROE cases and, in cases involving the placement of the base ROE above the central tendency of the zone of reasonableness, the Commission has used the central tendency of the top half of the zone. Our decision to utilize the midpoint of the upper half of the zone is based on the record evidence in this proceeding and is consistent with the Commission's established policy of using the midpoint of the ROEs in a proxy group when establishing a central tendency for a region-wide group of utilities.[571]

277. We also disagree with the assertion that there is no evidence to support the specific upward adjustment. Such exactitude has never been required in determining the appropriate placement of ROEs within the zone of reasonableness or for determining the appropriate size of incentives. The Commission maintains discretion to use its judgment in weighing factors specific to a given proceeding to determine where within the zone of reasonableness the final base ROE should be placed.

278. The Commission has held that the midpoint is the appropriate measure of the central tendency for groups of utilities.[572] That determination is not altered by the use of the midpoint of the upper half of the zone of reasonableness.

---

[569] Initial Decision, 153 FERC ¶ 63,027 at P 118.

[570] Opinion No 531-B, 150 FERC ¶ 61,165 at P 55.

[571] *SoCal Edison*, 131 FERC ¶ 61,020 at P 92, *aff'd in relevant part, S. Cal. Edison Co. v. FERC*, 717 F.3d at 185-87.

[572] *See*, *e.g.*, S. *Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 91.

279. In response to Joint Customer Intervenors, while anomalous market conditions reduce the Commission's confidence in the establishment of the ROE at the midpoint of the zone of reasonableness, the Commission has not required a precise correlative relationship between a particular ROE and a desired level of transmission investment. Additionally, while we disagree with Complainants' proposed quartile approach, we also find that Joint Customer Intervenors failed to convince us that the 75th percentile of the zone of reasonableness reflects the appropriate base ROE here.

280. We disagree with OMS' argument that the Presiding Judge erred in not considering that the alternative benchmarks indicate that the ROE should be lower than the upper midpoint. MISO TOs' risk premium and expected earnings analyses, which the Commission accepts as discussed above, featured respective midpoint ROEs of 10.36 and 11.99 percent, both of which *exceed* the upper midpoint, indicating that the upper midpoint is not generally higher than the ROEs produced by the alternative benchmarks.

281. Finally, we reject the Complainants' proposal to set MISO TOs' ROE at 9.08 percent based on their four quartile approach. A base ROE of 9.08 percent would be below the 9.29 percent midpoint of the DCF zone of reasonableness in this case. The Complaints' proposal is thus contrary to our holding above that MISO TOs' ROE should be set at a point above the midpoint of the zone of reasonableness.

D. Other Issues

1. Capital Structure

a. Initial Decision

282. At hearing, Complainants and JCA both propose that whatever base ROEs are approved in this proceeding be reduced for all MISO TOs with equity ratios of 55 percent or higher. Mr. Gorman contends that the base ROEs of these utilities should be lowered by 20 basis points.[573] Mr. Hill recommends that the allowed base ROEs of MISO TOs that have common equity ratios of 55 percent or above should be adjusted downward five basis points for every one percent difference between the ratemaking common equity ratio and 49 percent (the average common equity ratio of what he refers to as "the electric utility sample group"). Conversely, he recommends that the base ROEs of firms with equity ratios at or below 45 percent should be adjusted upward five basis points for every one percent difference between the ratemaking common equity ratio and 49 percent.[574]

[573] Exh. JC-1 at 36:13-17.

[574] Exh. JCA-1 at 43:27–44:9; Exh. JCA-11 at 63-64.

Both Complainants/Joint Consumer Advocates contended that a utility with a higher equity ratio is less risky than comparable utilities with lower equity ratios, and that its base ROE should be lowered to reflect that rate differential.[575]

283. The Presiding Judge rejected proposals to adjust MISO TOs' base ROE based on their equity ratios. The Presiding Judge determined that these arguments amounted to a collateral attack on the Commission's rejection in the Hearing Order of an argument that it should cap MISO TOs' actual or hypothetical capital structure at 50 percent equity. The Presiding Judge concluded that lowering the base ROE for utilities with an equity ratio greater than 50 percent would "do indirectly what the Commission said it would not do directly."[576] The Presiding Judge further noted that the Commission's approach to setting the base ROE already incorporates measures of the utilities' risk, obviating the need to account for the effect of capital structure on risk.

b. <u>Briefs on Exceptions</u>

284. Complainants argue that the Presiding Judge erred in rejecting Complainants' recommended capital structure-based ROE adjustments as a collateral attack on the Hearing Order. Complainants argue that the Hearing Order did not foreclose consideration of all issues related to MISO TOs' capital structure for evaluating the base ROE such that their argument warrants consideration.[577] Specifically, the Commission found that issues regarding capital structures "are best addressed with respect to that ROE, which the Commission is setting for hearing."[578] Complainants state that an equity-heavy capital structure increases costs to ratepayers and recommends a 20 basis point reduction to the base ROE of MISO TOs whose common equity structure exceeds 55 percent to account for their lower risk.[579]

---

[575] Exh. JC-1 at 20-21; Exh. JCA-11 at 45.

[576] Initial Decision, 153 FERC ¶ 63,027 at P 483.

[577] Complainants Brief on Exceptions at 51.

[578] *Id.* at 51-52 (citing Hearing Order, 149 FERC ¶ 61,049 at P 199).

[579] Complainants Brief on Exceptions at 52 (citing Complainants Initial Brief at 90; *see also* Complainants Reply Brief at 39-41).

c. Briefs Opposing Exceptions

285. MISO TOs also argue that the Presiding Judge correctly rejected Complainants' collateral attack on the Hearing Order's rejection of a cap on common equity ratios.[580]

d. Commission Determination

286. We disagree with Complainants' argument that the Commission should reduce the base ROEs of utilities with capital structures featuring at least 55 percent equity by 20 basis points. Although this proposal is not beyond the scope of this proceeding, as it is distinct from Complainants' request to prohibit equity-rich capital structures, it is insufficiently supported and inconsistent with the Commission's methodology for determining where in the DCF zone of reasonableness to place a specific public utility. While the Commission has indeed adjusted a company's base ROE above or below the central tendency of the zone of reasonableness based on the relative risk analysis,[581] it does so only after a full evaluation of all relevant factors including both business and financial risk.[582] This is because lower financial risk may be offset by higher business risk or vice versa. Complainants have provided no such complete evaluation of any of the MISO TOs' relative risk versus the proxy group. Rather, they seek a risk adjustment based upon a single factor, an alleged equity-rich capital structure, without consideration of any other risk factor. This is contrary to Commission policy.

287. Moreover, although equity-rich capital structures may reduce utility risk Complainants have not attempted to justify or provide quantitative support for presumably arbitrary 55 percent threshold for this penalty. Additionally, Complainants' observation that their proposed 20 basis-point reduction is approximately one third of the difference between the spread between A and Baa utility bond yields for the six months ending December 2014,[583] lacks quantitative support such that it does not make the

[580] MISO TOs Brief Opposing Exceptions at 49-51.

[581] *See, e.g.*, *Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d at 57 ("Once the Commission has defined a zone of reasonableness [using the DCF model], it then assigns the pipeline a rate within that range to reflect specific investment risks associated with that pipeline as compared to the proxy group companies").

[582] *See, e.g.*, *El Paso Natural Gas Co.*, Opinion No. 528-A, 154 FERC ¶ 61,120 at PP 302-340 (2016) (Opinion No. 528-A).

[583] *See* Exh. MTO-1 at 36.

choice of this threshold any less arbitrary. Complainants provide no evidence of how much a higher return correlates with a higher credit rating. Complainants also do not justify why their proposed ROE reduction should apply to all utilities with equity percentages above 55 percent, regardless of what the equity percentage is.

288. In any event, Complainants' position fails to take into account the fact that our criteria for selecting members of the proxy group are intended to produce a proxy group made up of companies of similar risk. Those criteria include screens to ensure that the proxy group contains only utilities with similar credit ratings to the utility at issue. To the extent that a higher percentage equity in the capital structure reduces a utility's risk, as Complainants and Joint Consumer Advocates assert, then the utility's credit rating would be correspondingly higher than that of a utility with a typical capital structure. The resulting higher credit ratings of members of the proxy group would reduce the calculated ROE, because higher-rated companies generally have lower ROEs. Consequently, additional reductions to the ROEs that are proposed by Complainants essentially reduce the ROE twice for featuring equity-rich capital structures.

289. Furthermore, as a policy matter, the Commission does not directly incentivize utilities' to adjust their preferred capital structures. The Commission has not previously directly encouraged utilities to feature more debt in their capital structure. We find that it would be inappropriate to encourage additional debt leveraging of utilities, many of which are undertaking large investments or do not have high credit ratings.

2. Formula Rate ROE Adjustments

a. Initial Decision

290. The Presiding Judge rejected the arguments of Joint Consumer Advocates and Joint Customer Intervenors that MISO TOs' formula rates reduce their business risks, at least relative to state-regulated utilities. The Presiding Judge observed that, although the parties appeared to "agree that formula rates reduce the risk of under-recovery, but deny the utility the benefits of over-recover[y]," the record did not indicate which effect was likely to predominate, making it impossible to determine the net effect of formula rates on a company's risk profile.[584] The Presiding Judge also concluded that the record did not contain evidence that the formula rates gave MISO TOs a significant advantage in more rapidly recovering their costs relative to state-regulated electric utilities.[585] In addition, the Presiding Judge distinguished a series of earlier Commission cases, in which

[584] Initial Decision, 153 FERC ¶ 63,027 at P 419.

[585] *Id.* PP 429-430, 432.

the Commission appeared to adopt the proposition that formula rates reduced a utility's business risk. The Presiding Judge explained that those cases involved generators that had contracted to sell electricity to corporate affiliates that agreed to purchase all of the generators' output and the generator had a formula rate that provided for the recovery of all its expenses — circumstances that the Presiding Judge determined were not present for MISO TOs.[586] Finally, the Presiding Judge also noted that "a formula rate . . . appears to best serve the public interest" and, therefore, that lowering a public utility's ROE on the basis that it receives a formula rate could run counter to Commission objectives.[587]

b. <u>Briefs on Exceptions</u>

291. Joint Customer Intervenors assert that the Presiding Judge failed to consider evidence demonstrating that the formula rate-based transmission service at issue here is less risky than the integrated generation and distribution service regulated by the state commissions.[588] OMS states that the Commission has explained that, in determining the ROE for public utilities, its evaluation of investment focuses on the two major sources of uncertainty to a company: the business risk and financial risk. OMS reiterates the arguments that Attachment O to the MISO Tariff – a comprehensive formula rate transmission rate – substantially mitigates the business risk faced by MISO TOs, and that this reduction in risk must be considered and given effect in determining a just and reasonable ROE for MISO TOs.[589] OMS states that the Presiding Judge rejected those arguments, citing three reasons why the availability of formula rates should not be a factor in the ROE determination. OMS contends that each of the three reasons relied upon by the Presiding Judge is erroneous.

292. First, OMS states that the Presiding Judge appears to have adopted MISO TOs' contention that formula rates are a double-edge sword; they eliminate the need for utilities to file rate cases when costs are increasing, but do not eliminate the risk of retroactive downward adjustments to rates when the formula has operated to over-recover costs.[590] OMS states that the inability to enjoy a windfall when costs are declining is not

---

[586] *Id.* PP 435-443.

[587] *Id.* PP 449-450.

[588] Joint Customer Intervenors Brief on Exceptions at 47-48 (citing Exh. JCI-4 at 32:21-36:2).

[589] OMS Brief on Exceptions at 44 citing OMS Initial Brief at 34-35.

[590] *Id.* (citing Initial Decision, 153 FERC ¶ 63,027 at P 446).

a factor that should be thought to balance out the mitigation of business risk formula rates provide in an increasing-cost environment.

293. Second, OMS states that the Presiding Judge found that formula rates serve the "public interest" because they ensure that a utility earns no more or less than its authorized Base ROE.[591] OMS states that this interest would be adversely affected, according to the Presiding Judge, if base ROEs were reduced to reflect the lower business risk faced by a company with a formula rate.[592] OMS argues that the Initial Decision's finding in this regard misses the point that was argued by OMS and others because it focuses on the pros and cons of formula rates from the point of view of utilities, not from the perspective of investors. OMS states that investors care more about the certainty of cost recovery over time than they do about the opportunity for short-term windfalls, and therefore investors require less of a return from companies that offer a certainty of cost recovery than they do from companies offering instead the remote chance for an occasional windfall.[593] OMS contends that, by failing to give effect to this fact, the Presiding Judge confers a Base ROE that is higher than the actual risk-adjusted cost of equity for companies with full-cost recovery formula rates.

294. Finally, OMS states that the Presiding Judge relies on the fact that "the Commission has recently ignored without comment contentions that it should reduce a utility's Base ROE based on its utilization of allegedly less risky formula rates."[594] OMS argues that the Commission's silence in *PATH* cannot be construed as a determination on the merits of the question, and the Commission made clear in a more recent incarnation of the *PATH* proceedings that "silence is not evidence of Commission policy."[595] Furthermore, OMS contends that in *PATH* and the other orders to which the Initial

[591] *Id.* at 45 (citing Initial Decision, 153 FERC ¶ 63,027 at P 447).

[592] *Id.* (citing Initial Decision, 153 FERC ¶ 63,027 at P 448).

[593] *Id.* n.155 ("It is well-established in the financial literature that investors are generally 'risk-averse.' This means that the required return for an investment that has symmetric expectations of gains and losses is greater than the required return for an investment with certainty of no gains or losses.").

[594] *Id.* at 46 (citing Initial Decision, 153 FERC ¶ 63,027 at P 445 (citing *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 (2008) (*PATH*))).

[595] *Id.* (citing *Potomac-Appalachian Transmission Highline, L.L.C.*, 153 FERC ¶ 61,308, at P 13 (2015)).

Decision alludes[596] (save one), the Commission declined to expressly recognize the risk-mitigating effects of formula rates in the context of considering ROE *incentives*, not in the context of determining a just and reasonable, properly risk-adjusted *base* ROE. That the Commission did not expressly give effect to the risk-mitigating impact of formula rates in ROE adder cases, according to OMS, says nothing about the ability of formula rates to mitigate the risks that are relevant in Base ROE cases. OMS states that the only case cited by the Presiding Judge that specifically addressed a utility's base ROE is *Virginia Electric & Power Company*, where the Commission reduced the requested base ROE without expressly addressing, one way or the other, the argument that formula rates mitigate risks.[597] OMS asserts that since silence is not evidence of Commission policy, the Initial Decision's reliance on these orders is not well-founded.

c. Briefs Opposing Exceptions

295. MISO TOs state that the Commission has previously found that formula rate tariffs do not fully mitigate the cost recovery risk of federally-regulated transmission or render public utilities less risky than state-regulated enterprises.[598]

296. In support of this argument, they state that the Commission has previously found that formula rate tariffs do not fully mitigate the cost recovery risk of federally-regulated transmission or render public utilities less risky than state-regulated enterprises.[599] Additionally, in response to OMS's argument that the Presiding Judge wrongly discounted Mr. Hill's comparable risk evidence, MISO TOs claim that OMS documented no errors in the Presiding Judge's finding that such evidence was outdated, inapplicable, incomplete, or inconsistent with testimony offered by other witnesses.[600] MISO TOs also argue that the Presiding Judge rightly determined that Mr. Solomon's testimony was incomplete, tangentially relevant, or not supportive of Mr. Solomon's position.[601]

---

[596] *Id.* at 46 (citing Initial Decision, 153 FERC ¶ 63,027 at n.570).

[597] *Id.* at 46-47 citing *Virginia Elec. & Power Co.*, 123 FERC ¶ 61,098, at P 58 (2008).

[598] MISO TOs Brief Opposing Exceptions at 35.

[599] *Id.*

[600] *Id.* at 35-36.

[601] *Id.* at 36.

d. Commission Determination

297. We affirm the Presiding Judge's determination that the use of formula rates does not warrant a lower base ROE. To the extent that formula rates reduce risk, they would, similar to the use of more equity in the capital structure, improve utility credit ratings. This would in turn affect the DCF proxy group based on screens requiring a group of similarly-rated utilities, diminishing the ROE produced by the DCF analysis. Additionally, nearly all electric utilities feature transmission formula rates. Consequently, the use of such formula rates is reflected in the proxy group within the DCF analysis.

298. Finally, as the Commission previously explained in Opinion No. 531, "when a public utility's ROE is changed, either under section 205 or section 206 of the FPA, that utility's total ROE, inclusive of transmission incentive ROE adders, should not exceed the top of the zone of reasonableness produced by the two-step DCF methodology," which in this case, would be 11.35 percent.[602] We therefore find that MISO TOs' total or maximum ROE, including transmission incentive ROE adders, cannot exceed 11.35 percent.[603]

The Commission orders:

(A) MISO TOs' base ROE is hereby set at 10.32 percent with a total or maximum ROE including incentives not to exceed 11.35 percent, effective on the date of this order, as discussed in the body of this order.

(B) MISO and MISO TOs are hereby directed to submit compliance filings with revised rates to be effective the date of this order reflecting a 10.32 percent base ROE and a total or maximum ROE not exceeding 11.35 percent (inclusive of transmission incentive ROE adders), within thirty (30) days of the date of this order, as discussed in the body of this order.

(C) MISO and MISO TOs are hereby directed to provide refunds, with interest calculated pursuant to 18 C.F.R. § 35.19a (2016), within thirty (30) days of the date of this order, for the 15-month refund period from November 13, 2013 through February 11, 2015, as discussed in the body of this order.

(D) MISO and MISO TOs are hereby directed to file a refund report

---

[602] Opinion No. 531, 147 FERC ¶ 61,234 at P 165.

[603] *See* Opinion No. 531-A, 149 FERC ¶ 61,032 at P 11.

detailing the principal amounts plus interest paid to each of their customers within forty-five (45) days of the date of this order.

By the Commission. Commissioner Honorable is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting Held December 5, 2012

Commissioners Present:

Robert F. Powelson, Chairman
John F. Coleman, Jr., Vice Chairman
Wayne E. Gardner, Dissenting in Part & Concurring in Result Only Statements
James H. Cawley, Dissenting in Part Statement
Pamela A. Witmer

Pennsylvania Public Utility Commission	R-2012-2290597
Office of Consumer Advocate	C-2012-2300266
Office of Small Business Advocate	C-2012-2301063
PP&L Industrial Customer Alliance	C-2012-2306728
William Andrews	C-2012-2300402
Tracey Andrews	C-2012-2328596
Eric Joseph Epstein	C-2012-2313283
Dave A. Kenney	C-2012-2299539
Roberta A. Kurrell	C-2012-2304870
Donald Leventry	C-2012-2304903
John G. Lucas	C-2012-2298593
Helen Schwika	C-2012-2299335

v.

PPL Electric Utilities Corporation

Table of Contents

OPINION AND ORDER

BY THE COMMISSION:

I. Matter Before the Commission

Before the Pennsylvania Public Utility Commission (Commission) for consideration and disposition is the Recommended Decision of Administrative Law Judge (ALJ) Susan D. Colwell, issued on October 19, 2012, relative to the above-captioned general rate increase proceeding. Also before the Commission are the Exceptions and Replies to Exceptions filed with respect thereto.

Exceptions to the Recommended Decision were filed on November 8, 2012, by the following Parties: PPL Electric Utilities Corporation (PPL or Company), the Commission's Bureau of Investigation and Enforcement (I&E), the Office of Consumer Advocate (OCA), the Office of Small Business Advocate (OSBA), the Commission on Economic Opportunity (CEO), Direct Energy Services LLC (Direct Energy), Dominion Retail, Inc. d/b/a Dominion Energy Solutions (DR), and the PP&L Industrial Customer Alliance (PPLICA). Replies to Exceptions were filed on November 19, 2012, by the following Parties: PPL, the OCA, the OSBA, DR, and PPLICA. I&E filed Replies to Exceptions on November 29, 2012.

II. History of the Proceeding[1]

On March 30, 2012, PPL filed Supplement No. 118 to Tariff – Electric Pa. P.U.C. No. 201, to become effective June 1, 2012, containing proposed changes in rates, rules, and regulations calculated to produce approximately $104.6 million in additional annual revenues. This proposed rate change represents an average increase in the Company's distribution rates of approximately 13%, which equates to an average increase in total rates (distribution, transmission, and generation charges) of approximately 2.9%. The filing was suspended by Commission Order entered on May 24, 2012.

Formal Complaints against this proposed tariff were filed by the following: the OCA, on April 23, 2012; the OSBA, on April 25, 2012; PPLICA, on May 25, 2012; John G. Lucas, on April 9, 2012; Helen Schwika, on April 11, 2012; Dave A. Kenney, on April 16, 2012; William Andrews, on April 19, 2012; Tracey Andrews, on May 1, 2012; Roberta Kurrell, on May 3, 2012; Donald Leventry, on May 15, 2012;[2] and Eric Joseph Epstein, on July 5, 2012. Petitions to intervene were filed by the following: DR, on April 9, 2012; the CEO, on April 30, 2012; the International Brotherhood of Electrical Workers Local 1600, on May 1, 2012; the Sustainable Energy Fund (SEF), on May 3, 2012; Direct Energy, on May 24, 2012; and Granger Energy of Honey Brook LLC and Granger Energy of Morgantown LLC (collectively, Granger), on May 24, 2012. I&E filed a Notice of Appearance on April 10, 2012.

---

[1] For a full and complete history, as well as information regarding the testimony provided during the Public Input hearings, please refer to the Recommended Decision at 2-10.

[2] By letter received on June 19, 2012, Mr. Leventry indicated that he did not want to be involved in the litigation and asked that he be removed from the service list.

A Prehearing Conference was held on May 31, 2012. On June 1, 2012, ALJ Colwell issued a Scheduling Order which adopted the schedule agreed to by the Parties at the Prehearing Conference.

On June 11, 2012, the Company filed a Motion for a Protective Order. No Party filed a responsive pleading, and the Protective Order was granted on July 3, 2012.

On June 18, 20, and 21, Public Input Hearings were held in Scranton, Wilkes-Barre, Bethlehem, Allentown, and Harrisburg.

On July 13, 2012, Richards Energy Group, Inc. (REG) submitted a late-filed Petition to Intervene. The ALJ granted the intervention by Order issued July 26, 2012.

The evidentiary hearings were held on August 6, 7, 9, and 10, 2012. A hearing was also held on October 11, 2012, to hear the testimony of Tracey Andrews, whose Formal Complaint was filed on May 1, 2012, but was not properly associated with this rate case until October 10, 2012. The record consists of a transcript of 613 pages and numerous statements and exhibits presented by various Parties, as detailed in Appendix A of the Recommended Decision.

On August 29, 2012, the Parties filed Main Briefs and the record was thereupon closed. In addition, PPL filed a Petition to Reopen the Record in order to provide updated information regarding the long-term debt issued on August 24, 2012. As no objections were received, by Order issued September 10, 2012, the ALJ reopened the record for the purpose of accepting the updated information.

On September 14, 2012, the Parties filed Reply Briefs. The record closed upon the receipt of the Reply Briefs.

By way of Recommended Decision, issued on October 19, 2012, ALJ Colwell recommended, *inter alia*, that the company be permitted to file tariffs or tariff supplements containing rates designed to produce a $63,830,000 increase to the Company's present revenues. I.D. at 141. As previously noted, PPL, I&E, the OCA, the OSBA, the CEO, Direct Energy, DR, and PPLICA filed Exceptions. PPL, the OCA, the OSBA, DR, and PPLICA filed Replies to Exceptions. I&E filed Replies to Exceptions on November 29, 2012, as well as a letter requesting that the Commission accept its Replies to Exceptions as timely filed.[3]

[3] In its letter, I&E stated that on November 19, 2012, it electronically served its Replies to Exceptions on all Parties and the Office of Administrative Law Judge and served hard copies upon all internal Commission offices. I&E averred that it did not discover until November 29, 2012, that due to an administrative error, its Replies to Exceptions were inadvertently uploaded for e-filing on November 19, 2012, rather than submitted for e-filing. Under these circumstances, we find it appropriate to consider I&E's Replies to Exceptions in the interest of securing a just, speedy and inexpensive determination in this proceeding. *See*, 52 Pa. Code § 1.2(a). We do not believe that any of the Parties to this proceeding will be prejudiced by our consideration of I&E's Replies to Exceptions, as the Parties and this Commission were timely served with them.

III. Discussion

A. Description of the Company

PPL is a jurisdictional electrical distribution company (EDC) providing electric distribution service to approximately 1.4 million customers in all or portions of twenty-nine counties in eastern and central Pennsylvania. Under its present corporate structure, it is a wholly owned subsidiary of PPL Corporation (PPL Corp.). Another subsidiary of PPL Corporation is PPL Services Corporation, which provides various administrative and general services to the utility, including legal services, human resources, auditing, and community affairs.

B. Legal Standards

In deciding this or any other general rate increase case brought under Section 1308(d) of the Public Utility Code (Code), 66 Pa. C.S. § 1308(d), certain general principles always apply. A public utility is entitled to an opportunity to earn a fair rate of return on the value of the property dedicated to public service. *Pa. PUC v. Pennsylvania Gas and Water Co.* 341 A.2d 239, 251 (Pa. Cmwlth. 1975). In determining a fair rate of return, the Commission is guided by the criteria provided by the United States Supreme Court in the landmark cases of *Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). In *Bluefield*, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or

> anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

Bluefield, 262 U.S. at 692-693.

The burden of proof to establish the justness and reasonableness of every element of a public utility's rate increase request rests solely upon the public utility in all proceedings filed under Section 1308(d) of the Code. The standard to be met by the public utility is set forth in Section 315(a) of the Code, 66 Pa. C.S. § 315(a), as follows:

> **Reasonableness of rates.** – In any proceeding upon the motion of the commission, involving any proposed or existing rate of any public utility, or in any proceedings upon complaint involving any proposed increase in rates, the burden of proof to show that the rate involved is just and reasonable shall be upon the public utility.

In reviewing Section 315(a) of the Code, the Pennsylvania Commonwealth Court interpreted a public utility's burden of proof in a rate proceeding as follows:

> Section 315(a) of the Public Utility Code, 66 Pa. C.S. § 315(a), places the burden of proving the justness and reasonableness of a proposed rate hike squarely on the public utility. *It is well-established that the evidence adduced by a utility to meet this burden must be substantial*.

Lower Frederick Twp. Water Co. v. Pa. PUC, 409 A.2d 505, 507 (Pa. Cmwlth. 1980) (emphasis added). *See also*, *Brockway Glass Co. v. Pa. PUC*, 437 A.2d 1067 (Pa. Cmwlth. 1981).

In general rate increase proceedings, it is well established that the burden of proof does not shift to parties challenging a requested rate increase. Rather, the utility's burden of establishing the justness and reasonableness of every component of its rate request is an affirmative one, and that burden remains with the public utility throughout the course of the rate proceeding. There is no similar burden placed on parties to justify a proposed adjustment to the Company's filing. The Pennsylvania Supreme Court has held:

> [T]he appellants did not have the burden of proving that the plant additions were improper, unnecessary or too costly; on the contrary, that burden is, by statute, on the utility to demonstrate the reasonable necessity and cost of the installations, and that is the burden which the utility patently failed to carry.

Berner v. Pa. PUC, 382 Pa. 622, 631, 116 A.2d 738, 744 (1955).

This does not mean, however, that in proving that its proposed rates are just and reasonable, a public utility must affirmatively defend every claim it has made in its filing, even those which no other party has questioned. As the Pennsylvania Commonwealth Court has held:

> While it is axiomatic that a utility has the burden of proving the justness and reasonableness of its proposed rates, it cannot be called upon to account for every action absent prior notice that such action is to be challenged.

Allegheny Center Assocs. v. Pa. PUC, 570 A.2d 149, 153 (Pa. Cmwlth. 1990) (citation omitted). *See also, Pa. PUC v. Equitable Gas Co.*, 73 Pa. P.U.C. 310, 359-360 (1990).

Additionally, Section 315(a) of the Code, 66 Pa. C.S. § 315(a), cannot reasonably be read to place the burden of proof on the utility with respect to an issue the utility did not include in its general rate case filing and which, frequently, the utility would oppose. Inasmuch as the Legislature is not presumed to intend an absurd result in interpretation of its enactments,[4] the burden of proof must be on the party who proposes a rate increase beyond that sought by the utility. The mere rejection of evidence contrary to that adduced by the public utility is not an impermissible shifting of the evidentiary burden. *United States Steel Corp. v. Pa. PUC*, 456 A.2d 686 (Pa. Cmwlth. 1983).

In analyzing a proposed general rate increase, the Commission determines a rate of return to be applied to a rate base measured by the aggregate value of all the utility's property used and useful in the public service. The Commission determines a proper rate of return by calculating the utility's capital structure and the cost of the different types of capital during the period in issue. The Commission is granted wide discretion, because of its administrative expertise, in determining the cost of capital. *Equitable Gas Co. v. Pa. PUC*, 405 A.2d 1055, 1059 (Pa. Cmwlth. 1979) (determination of cost of capital is basically a matter of judgment which should be left to the regulatory agency and not disturbed absent an abuse of discretion).

As we proceed in our review of the various positions of the Parties in this proceeding, we are reminded that any issue or Exception that we do not specifically address shall be deemed to have been duly considered and denied without further discussion. The Commission is not required to consider expressly or at length each contention or argument raised by the parties. *Consolidated Rail Corp. v. Pa. PUC,* 625 A.2d 741 (Pa. Cmwlth. 1993); *also see, generally, University of Pennsylvania v. Pa. PUC*, 485 A.2d 1217 (Pa. Cmwlth. 1984).

---

[4] 1 Pa. C.S. § 1922(1), *PA Financial Responsibility Assigned Claims Plan v. English*, 541 Pa. 424, 430-431, 64 A.2d 84, 87 (1995).

C. Rate Base

1. Depreciation Reserve

a. Positions of the Parties

In its filing, PPL claimed $1.813 billion in its Accumulated Reserve for Depreciation based on plant in service and amortization of net salvage for the test year ending December 31, 2012. PPL Future 1-Revised, Sch. C-1. PPL reflected depreciation accruals of $155.248 million and proposed that the Commission recognize annual depreciation expenses of $168.92 million. PPL Exh. Future 1-Revised, Sch.D-10.

PPL explained that rate base items are not annualized but are the balances projected to be in effect at the end of the test year. PPL also explained that annualization applies only to revenue and expense items, and not to rate base items. PPL M.B. at 22. PPL averred that the OCA's approach of using a non-annualized level of plant in service with an annualized level of depreciation reserve would create a mismatch between plant in service and the accumulated reserve for depreciation, which would result in an overstatement of the accumulated depreciation reserve and an understatement of rate base. PPL further asserted that the OCA's approach is inconsistent with the fundamentals of test year ratemaking, because by including annualized depreciation expense in the calculation of the accumulated depreciation reserve, the OCA's adjustment would add depreciation expense to the reserve that has not and will not be accrued at the end of the future test year (FTY). *Id*. at 23.

The OCA recommended that the Company's proposed level of Accumulated Reserve for Depreciation be increased by $10.417 million to better match the claimed depreciation expense, resulting in a corresponding reduction to PPL's rate base of $10.417 million. OCA M.B. at 12; OCA St. 1-REV. at 11-12; Exh. KC-1-REV. Sched. 2 at 3. The OCA averred that, since ratepayers are being asked to pay for the full level of depreciation expense, it is appropriate for ratepayers to have the full amount of that expense applied to accumulated depreciation. OCA M.B. at 13; OCA St. 1-SR at 4.

b. ALJ's Recommendation

The ALJ recommended adoption of PPL's position to use the accrued depreciation amount of $155.248 million for calculating the depreciation reserve, rather than the claimed $168.92 million in depreciation expense. R.D. at 17. The ALJ agreed with the Company's reasoning that rate base items are not annualized but are the balances which are projected to be in effect at the end of the year. *Id*. at 16, 17. The ALJ found the Company's following argument persuasive:

> The reserve for depreciation is built up by recording depreciation expense, but the expense recorded is the expense per books for a particular period of time, here calendar year 2012. OCA's proposal to ignore the projected per books depreciation expense and use instead the theoretical, annualized level of expense is not correct. The annualized depreciation expense as of December 31, 2012 will not be recorded on PPL Electric's books during calendar year 2012. Therefore, it is not part of the "build-up" of the depreciation reserve by recording depreciation expense related to plant in service.

Id. at 17-18 (citing PPL R.B. at 9-10). Accordingly, the ALJ recommended that the OCA's proposed $10.417 million adjustment be rejected. *Id*. at 18.

c. Exceptions

In its Exceptions, the OCA avers that the ALJ erred by rejecting the OCA's accumulated reserve for depreciation adjustment. The OCA states that it recommended an adjustment to PPL's accumulated reserve for depreciation to match PPL's claimed depreciation expense. OCA Exc. at 2; OCA St. 1-REV. at 11-12; Exh. KC-1-REV.

Sched. 2 at 3. The OCA explains its position that the depreciation expense included in the cost of service and the additions to the depreciation reserve, which are deducted from rate base, should be based on the level of plant the Company claims will be in service at the end of the FTY and the depreciation expense claimed for the FTY that is related to that plant. OCA Exc. at 2-3. The OCA asserts that ratepayers should receive the full benefit of the depreciation expense for which they are being charged by receiving the corresponding full benefit of accumulated depreciation reserve. *Id*. at 3.

In its Replies to Exceptions, PPL states that the ALJ properly rejected the OCA's proposal. PPL R.Exc. at 11. PPL submits that the accumulated reserve for depreciation, plant in service, and retirements as of December 31, 2012, are determined by bringing forward the book balances as of December 31, 2011, by reflecting the projected plant additions, annual depreciation expense per books, projected retirements per books, and projected net salvage per books. *Id*. at 11; PPL Exh. JJS-2 at III-6-III-7; PPL Exh. 1, Part V-A-3 at 1-3. PPL also submits that the OCA is proposing to change only one of these elements in determining net plant in service – the projected depreciation expense per books for 2012. PPL avers that the OCA's proposed adjustment is flawed, because the use of the annualized depreciation expense would be a mismatch with every other component of net plant in service, as those components are based on projected transactions per books. PPL asserts that there is not an annualized level of plant in service as of December 31, nor are there annualized retirements or annualized net salvage. PPL R.Exc. at 11. PPL further avers that its method of determining the accumulated reserve for depreciation was approved in its prior rate proceeding and has been accepted by the Commission for all major electric, gas, and water public utilities. *Id*.; PPL St. 13-R at 4.

d. Disposition

Based on our review of the record, the Parties' positions, and the Recommended Decision, we find that the ALJ properly adopted PPL's claim and rejected the OCA's proposal to use an annualized level of depreciation. PPL has met its burden of proof by showing that its method of determining the accumulated reserve for depreciation is reasonable, is consistent with the fundamentals of test year ratemaking, and is consistent with the methods used by other major public utilities. We agree with PPL that rate base items are not annualized but are balances to be in effect at the end of the test year. PPL is correct that the OCA's proposed adjustment to use a non-annualized level of plant in service with an annualized level of depreciation reserve would create a mismatch between plant in service and the accumulated reserve for depreciation, which would result in an overstatement of the accumulated depreciation reserve and an understatement of rate base. For these reasons, we shall deny the OCA's Exceptions and adopt the ALJ's decision on this issue.

2. Cash Working Capital – Lag Days for Payments to Affiliates

a. Positions of the Parties

PPL explained that its expense lag days for payments to its affiliate for support services is thirty-five days, consisting of the sum of fifteen days, which is the midpoint of the monthly service period, and twenty days, which is a standard accounting transaction for the preceding month. PPL M.B. at 24. PPL stated that it treats its payments to affiliates in the same manner that it treats its payments to non-affiliated vendors, and that it should not discriminate in favor of, or against, its affiliates. PPL also stated that a payment lag of thirty days is commercially reasonable and typical of the terms required by PPL's vendors. PPL asserted that it has consistently incorporated a thirty-five day payment lag for its affiliates in previous rate cases, and the Commission and the other parties to those proceedings have accepted the thirty-five day payment lag for affiliated services in calculating cash working capital (CWC) requirements. *Id*. at 25; PPL St. 7-R at 3.

I&E recommended a reduction in the CWC operation and maintenance (O&M) claims based on its position that PPL unnecessarily pays its affiliate substantially in advance of the required due date under the Company's service agreement with its affiliate. I&E submitted that, under the service agreement, PPL is billed monthly and has sixty days to pay its affiliate. Therefore, I&E argued that PPL has an allowable payment lag of seventy-five days pursuant to contract. I&E M.B. at 12. I&E proposed changing the payment date to the affiliate which, when weighted with the other expense groups, would result in an overall average expense lag payment of approximately forty-eight days, compared to PPL's claimed average expense payment lag of approximately thirty-five days. *Id*.; I&E St. 2 at 56. Application of I&E's recommendation would result in a $13,021,000 reduction to the Company's CWC claim to rate base. I&E M.B. at 11; I&E St. 2 at 56. I&E further argued that PPL did not provide any evidence that it has consistently incorporated a thirty-five day affiliate payment lag in its prior rates cases. I&E R.B. at 10. According to I&E, no prior litigated case addressed CWC generally or this O&M expense lag specifically, and there are no prior applicable Commission Orders providing the Company with Commission approval for this expense lag. *Id*. at 10-11.

b. ALJ's Recommendation

The ALJ adopted I&E's recommendation for a $13.021 million reduction to O&M in the CWC component of the Company's claimed rate base. The ALJ found persuasive I&E's argument that PPL did not have to pay its affiliate for services within the time period that the Company claimed but had the discretion to take advantage of a longer payment period of up to sixty days under the terms of the contract with its affiliate. The ALJ did not believe that PPL met its burden of proving its claim was reasonable, because the Company was causing the ratepayers a substantial amount of money due to a practice it could not otherwise justify except by saying that it has always been done that way. R.D. at 20.

c. Exceptions

In its Exceptions, PPL avers that the Recommended Decision's proposed adjustment to its lag days for payments to its affiliate should be rejected. PPL Exc. at 35. PPL submits that it uses a computerized system to pay all of its invoices from PPL Services and non-affiliated vendors. The Company notes that it pays its affiliates on the twentieth day of the month after services are received, which results in a thirty-five day payment lag for services it receives from its affiliates. PPL asserts that the ALJ's reliance on the payment terms in the agreement with its affiliate is not an adequate basis for the adjustment, because the agreement does not require a sixty-day payment period and clearly authorizes a twenty-day payment period. The Company explains that the agreement was entered into seventeen years ago when computers were not used to the extent they are currently and a longer time period for invoice payment was more common. *Id*. at 36.

I&E rejoins that the ALJ properly rejected PPL's calculation of its expense lag days based on the evidence presented by I&E, which demonstrated that the Company paid its affiliate well in advance of the due date, thereby resulting in a significantly shorter expense payment lag and an unnecessary annual ratepayer CWC contribution of $1.1 million. I&E R.Exc. at 3; I&E St. 2-SR at 62. I&E believes that PPL should be required to save its ratepayers $1.1 million annually by paying its affiliate as permitted under the agreement. I&E asserts that the manner in which PPL pays its affiliate disadvantages ratepayers and benefits its affiliate. I&E submits that, as a regulated monopoly with captive ratepayers, PPL should be held to a strict standard regarding the manner in which it handles payments to affiliates. I&E R.Exc. at 4.

d. Disposition

We agree with the ALJ's decision to adopt I&E's recommended $13.021 million O&M reduction to the CWC component of the Company's claimed rate base. PPL did not meet its burden of proving that its expense lag days for payments to its affiliate are reasonable. Since PPL has up to sixty days to pay its affiliate under the agreement, it would have been reasonable for PPL to take advantage of the longer payment period and, by doing so, to minimize the rate impact on its customers. PPL has control over when it pays its affiliate and can alter its computerized system to change the date on which it pays its affiliate. The evidence presented by I&E demonstrated that PPL's choice to pay its affiliate forty days early resulted in an annual ratepayer CWC contribution of $1.1 million. I&E St. 2-SR at 62. PPL's customers should not be burdened with this expense when it can be avoided. For these reasons, we shall deny PPL's Exception and adopt the ALJ's decision on this matter.

3. Cash Working Capital – Prepayment of Postage Expense

a. Positions of the Parties

PPL averred that it is proper for postage expense to be reflected in both the operation and maintenance expense component of working capital and prepayments, because each component addresses the expense during separate and distinct time periods. PPL M.B. at 26. PPL explained that the first time period related to postage expense is the prepayment, which begins when it makes prepayments to the United States Postal Service for postage to be used by the postage meter and ends when the postage meter adds postage to an envelope. According to PPL, the second time period is the payment lag, which begins when the postage is used. During the second time period, the expense appears in the working capital requirement as an O&M expense to reflect the period between when the postage meter adds postage to an envelope and when customers pay PPL. PPL's position was that there is no double recovery, because the inclusion of postage expense as a prepayment is separate from its treatment as an O&M expense in the working capital calculation. *Id*. at 27; PPL St. 7-R at 6-7. In its Reply Brief, PPL stated that its position that there is no double recovery was consistent with controlling Commission precedent, particularly the Commission's decision in the Company's 2004 rate case. PPL R.B. at 14 (citing *Pa. PUC v. PPL Electric Utilities Corp*., Docket No. R-00049255, at 11-12 (Order entered December 22, 2004)).

I&E did not recommend a specific adjustment to the Company's treatment of postage expense, but stated that the Company should be ordered to discontinue this practice in future proceedings because it is an improper CWC calculation that overstates the Company's CWC needs. I&E M.B. at 18. I&E averred that PPL includes a full twelve-month expense dollar amount claim for postage in its total CWC O&M expense, and also includes a twelve-month average prepayment dollar amount for postage in the Prepayment CWC component. *Id*. at 17. I&E's position was that this practice overstates the actual CWC requirement for postage, because the inclusion of two different CWC components results in a funding claim that is greater than what is incurred on an annual basis. *Id*. at 17-18.

b. ALJ's Recommendation

ALJ Colwell agreed with I&E's position. The ALJ found that PPL should discontinue its practice of including the same CWC need for postage in both the O&M expense and prepayment components of the CWC calculation, because this practice improperly inflates the CWC calculation. R.D. at 22. The ALJ distinguished this case from PPL's 2004 rate case. The ALJ stated that, in the 2004 case, the Commission accepted ALJ Turner's finding that the evidence did not support a conclusion that the Company prepaid its postage, which ALJ Turner admitted would have changed her recommendation. In this case, ALJ Colwell noted that PPL admitted to prepaying for postage and using the prepaid postage in its postage meter. R.D. at 21.

c. Exceptions

In its Exceptions, PPL avers that it should be permitted to continue to calculate the postage expense component of working capital as it has been calculating it. PPL states that it has fully explained its treatment of postage expense in rate base in its briefs. PPL also states that the Commission previously approved its treatment of postage expense and that nothing has changed since the Commission's previous approval. PPL Exc. at 37 (citing *Pa. PUC v. PPL Electric Utilities Corp*., Docket No. R-00049255, at 11-12 (Order entered December 22, 2004)).

In its Replies to Exceptions, I&E states that the ALJ correctly found that the Company overstated postage and that the Company should correctly calculate its postage expense in future proceedings. I&E avers that PPL improperly included postage expense as both an O&M expense and a prepayment, which resulted in a funding claim greater than the Company incurred. I&E believes that PPL's 2004 rate case is distinguishable from this case because, in that case, the OCA did not provide evidence that the Company included a prepayment and an expense for the same item, whereas, the Company admitted that it did in this case. I&E submits that PPL's CWC claim for postage is overstated, because, whether loaded into a meter or directly expensed, postage is paid only once. I&E R.Exc. at 5.

d. Disposition

Based on our review of the record, the Parties' positions, and the ALJ's decision, we find that PPL improperly included the same postage expense in two CWC components by listing it as both an O&M expense and a prepayment, resulting in an overstatement of that expenditure. We do not find merit in PPL's reliance on our Order in the Company's 2004 rate case. We agree with the ALJ and I&E that this case is distinguishable from the 2004 rate case. In the 2004 case, PPL included a claim for the net lag in recovery of operating expenses based upon a lead/lag study and a separate claim for average prepayments. In that case, PPL stated that the time period captured in its lead/lag study was from the date the bills were mailed to the date payment was received from customers, thus, excluding the time period from when the postage was paid to when it was expensed. *Pa. PUC v. PPL Electric Utilities Corp*., Docket No. R-00049255, at 11 (Order entered December 22, 2004). In the 2004 case, we concluded that the Company's position refuted the OCA's argument of double counting, because the time period from when the postage was paid to when it was expensed was excluded. *Id*. at 12. In the present case, PPL is expressly claiming that it properly included a prepayment and an expense for the same postage item. Accordingly, we shall adopt the ALJ's recommendation that PPL discontinue its practice of including the same CWC need for postage in both the O&M expense and prepayment components of the CWC calculation and deny PPL's Exception.

4. Cash Working Capital – Prepayment of Regulatory Assessments

a. Positions of the Parties

PPL stated that, consistent with Commission precedent, it included the Commission assessment in the prepayment component of its working capital requirement. PPL M.B. at 28 (citing *Pa. PUC v. National Fuel Gas Distribution Corp*., 1994 Pa. PUC Lexis 134). PPL stated that, while the Commission's assessment is calculated based on a utility's jurisdictional revenue for the prior calendar year, the assessment applies for the forthcoming fiscal year as provided in the Commission's June 21, 2012 invoice. PPL quoted the language in the Commission's invoice as follows:

> The Commission is submitting a request for **pre-payment** of PPL Electric's estimated Public Utility Commission assessment for the fiscal year 2012-2013. The requested pre-payment amount is an estimate based on the revenues shown

> on your Company's GAO-11 submission and the Commission's **fiscal year 2012-2013 budget** request. When the assessment invoices are issued in August for the **fiscal year 2012-2013** your invoice will be adjusted to reflect the payment made in response to this letter.

PPL M.B. at 29; PPL Exh. BLJ-1 (emphasis added).

PPL averred that its position that the assessment is for the fiscal year beginning on the following July 1 is also supported by the language in Section 510 of the Code, 66 Pa.C.S. § 510. PPL explained that, under Section 510, the Commission budget is proposed to the Governor and the General Assembly the preceding November 1, and the General Assembly is expected to approve a Commission budget for the upcoming fiscal year by the preceding March 30. PPL stated that, based on the approved budget, the Commission allocates the assessment among public utilities according to each utility's jurisdictional revenues for the preceding calendar year. PPL stated that, once the Commission makes the calculations, it prepares payment requests that the utilities receive in June prior to the fiscal year for which the assessment is made. PPL M.B. at 29.

I&E recommended removing the Company's claimed Commission assessments from the prepayments component of its CWC claim, which would result in an allowable working capital prepayment of $394,000, a reduction of $2.78 million to the Company's working capital prepayment claim. I&E averred that the Commission assessment is not a prepayment. I&E explained that the assessment is calculated as a proportion of Commission, OCA, and OSBA services that have been provided to PPL's utility type in the prior year, and it is billed as a percentage assessed on PPL's prior calendar year jurisdictional revenue and payable to the Commission, the OCA, and the OSBA in the subsequent calendar year. I&E M.B. at 15. I&E opined that the assessment is akin to a tax and, thus, should be treated as an expense with an associated lag. I&E argued that the assessment should be matched against the revenue generation time period on which the expense was based, namely, the prior year's jurisdictional revenue. *Id*. at 16.

b. ALJ's Recommendation

The ALJ recommended that I&E's proposal to remove PPL's Commission assessment expense as a prepayment under its CWC calculation be denied. The ALJ stated that several large utilities, including PPL, pay their assessments, or a portion of them, early in order to assure continued funding of the Commission's activities for the first quarter of the fiscal year. The ALJ found that it was clear that the assessment is based on a prior year's revenues, but the application period is the following fiscal year. R.D. at 23.

c. Exceptions

In its Exceptions, I&E avers that the ALJ erred by recommending rejection of I&E's adjustment to remove PPL's claimed regulatory assessments from the prepayments component of its CWC claim. I&E Exc. at 4. I&E states that the ALJ's finding that the regulatory assessment is a prepayment due to the time period in which the actual funds are spent is erroneous. I&E Exc. at 5. I&E contends that, under Section 510(b) of the Code, 66 Pa. C.S. § 510(b), although the assessment is paid in the subsequent fiscal year, the assessment covers the regulatory expenses incurred in the prior year. As such, I&E asserts that the assessment is not a prepayment for the next year's expenses, and it should be treated as an expense with an associated lag. *Id*. at 6.

I&E also distinguishes assessments from prepayments because prepayments are paid in advance of a service and may be refunded if the service is terminated before the end of the service period, whereas a utility's assessments are representative of the proportion of agency services rendered to the utility in the prior year and are not subject to a refund if the utility ceases operations the following year. *Id*. I&E believes that for ratemaking purposes, the assessment, which is a billed expense, must be matched against the revenue generation time period on which the expense was based, which is the prior year's jurisdictional revenue. I&E avers that this practice is consistent with the manner in which the assessment is made and with the accrual accounting concept of matching expenses with the revenue earning period that manifested the expenses, or matching revenues with the expenses that result from the production of those revenues. *Id*. at 7; I&E St. 2-SR at 63.

I&E further submits that the Commission's June assessment letter does not support the ALJ's recommendation. I&E describes the assessment process and states that the assessment is based upon the utilities' prior calendar year revenues, which must be reported by March of the following calendar year. I&E Exc. at 7. While assessments are made in August of a fiscal year, the Commission issues letters in June, such as the one issued to PPL, asking certain larger utilities to submit an early payment of the fiscal year's assessment based on a preliminary early assessment provided by the Commission. *Id*. at 7-8; PPL Exh. BLJ-1. Thus, I&E avers that the Commission's use of the word "prepayment" in the June assessment letter is merely a request for an early payment to assure the continuous funding of regulatory agencies, and is not determinative of the status of the assessment payment for purposes of the proper calculation of PPL's CWC requirements. *Id*. at 8.

In its Replies to Exceptions, PPL avers that the ALJ properly included regulatory assessments as a prepayment in the working capital calculation. PPL states that I&E's proposed adjustment is inconsistent with the Commission's invoice for assessments, the relevant law, and the manner in which the Commission operates. According to PPL, the language in the Commission's invoice supports its position that regulatory assessments are a prepayment. PPL R.Exc. at 14. PPL states that Section

511(b) of the Code, 66 Pa. C.S. § 511(b), also supports its position. *Id*. at 14-15.[5] PPL asserts that I&E's position suggests that regulatory assessments are paid after the fact and, if this were true, the Commission would have to borrow money to fund operations while collections of assessments were pending. PPL believes that I&E's position ignores reality and the way the Commission operates. *Id*. at 15.

d. Disposition

We find that PPL properly included the Commission assessment in the prepayment component of its working capital requirement. PPL presented evidence to show that, based on the language in the Commission's June 21, 2012 invoice, the assessment applies for the forthcoming fiscal year, July 1 through June 30. *See,* PPL St. 7-R at 3-4; PPL Exh. BLJ-1. PPL also presented evidence demonstrating that, pursuant to the assessment process set forth in Section 510 of the Code, 66 Pa. C.S. § 510, the assessment payment qualifies as a prepayment. PPL St. 7-R at 4. While it is clear under Section 510 that the assessment is calculated based on operating revenues for the preceding calendar year, the assessment that a utility pays is for the upcoming fiscal year. Moreover, PPL paid its assessment early, as requested in the Commission's invoice, and based its prepayment calculation on the manner in which it handles its assessment payments. *Id*. PPL's inclusion of the assessment as a prepayment is consistent with our prior decisions. *See, Pa. PUC v. National Fuel Gas Distribution Corp*., 1994 Pa. PUC Lexis 134, *29-30 (permitting the public utility to include in rate base a prepayment

---

[5] PPL quotes Section 511(b) of the Code, which provides the following:

> All such assessments and fees, having been **advanced** by public utilities for the purpose of defraying the cost of administering this part, shall be held in trust solely for that purpose, and shall be earmarked for the use of, and annually appropriated to, the commission for disbursement solely for that purpose.

PPL R.Exc. at 15 (quoting 66 Pa. C.S. § 511(b) (emphasis added)).

balance that included the Commission's assessment). For these reasons, we shall deny I&E's Exceptions and adopt the ALJ's decision on this issue.

D. Expenses

1. Incentive Compensation

a. Positions of the Parties

PPL provides three types of compensation to its employees: base pay, benefits, and eligibility for incentive compensation. PPL makes incentive compensation payments to its own employees and reimburses PPL Services for its share of PPL Services' incentive compensation, which enables PPL Services to make incentive payments to its eligible employees. PPL St. 3-R at 15-26; PPL M.B. at 33.

The OCA recommended disallowing half of the incentive compensation expense, thereby requiring the shareholders to share equally in the cost of the compensation plans. The OCA recommendation is to adjust the expenses of $4.468 million for the Company's incentive compensation plan and $4.902 million related to the PPL Services' incentive compensation plan downward. OCA Exh. KC-1-SR, Sch. 4 at 4; Sch. 1 at 2.

I&E recommended an equal sharing of the claimed incentive compensation expenses between shareholders and ratepayers, resulting in a jurisdictional allowance of $4.459 million and a reduction of the same amount from PPL's claim. I&E asserted that PPL has provided no evidence that the incurrence of this cost is necessary for the provision of safe and reliable service at just and reasonable rates. I&E M.B. at 28-29.

PPL argued that the incentive compensation payments are a part of the total compensation package that was developed and is maintained based, at least in part, on a comparison with those of other employers for comparable positions. PPL stated that, if the incentive compensation payments to employees were eliminated, the fixed compensation would have to be raised in order to remain competitive with other employers, and "[t]here would be no savings to ratepayers." PPL St. 3-R at 16-17; PPL M.B. at 34.

Further, PPL stated that the Commission has approved incentive compensation programs in numerous prior rate cases. PPL M.B. at 36-37 (citing *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket No. R-00072711, at 20-21 (Order entered July 31, 2008); *Pa. PUC v. PPL Gas Utilities Corporation*, Docket No. R-00061398, at 40 (Order entered February 8, 2007)).

b. ALJ's Recommendation

The ALJ stated that, because the Parties have not challenged the reasonableness of the total compensation expense, the overall amount was not at issue; rather, only the method of recovery was at issue. While the two public advocates rely on the inherent fairness of having shareholders fund half of the incentive program, since they too receive a benefit, the ALJ found that the law does not support that concept. Rather, the ALJ found that a utility is entitled to recover in rates all expenses reasonably necessary to provide service to its customers and to earn a fair return on its investment in plant used and useful in providing service. The ALJ stated that to require a sharing of expense is to deny that portion in a rate case, which is simply not permitted under case law. R.D. at 28 (citing *Butler Township Water Co. v. Pa. PUC,* 473 A.2d 219, 221, 222 (Pa. Cmwlth. 1984); *T.W. Phillips Gas and Oil Co. v. Pa. PUC*, 474 A.2d 355 (Pa. Cmwlth. 1984)). Based upon the above rationale, the ALJ recommended that PPL be permitted full recovery of its incentive compensation plan. R.D. at 27-28.

c. Exceptions

The OCA and I&E excepted to the ALJ's recommended full recovery of PPL's incentive compensation plan. As presented in its Main and Reply Briefs and in its Exceptions, the OCA asserted that there is ample case law to support the OCA's position that shareholders should fund a portion of the incentive compensation plan. OCA Exc. at 3 (citing *Pa. PUC v. Philadelphia Gas Works*, 2007 Pa. PUC Lexis 45; *Pa. PUC v. UGI Utilities, Inc. - Electric Division*, 82 Pa. P.U.C. 488, 508 (1994); *Pa. PUC v. Roaring Creek Water Co*., 1994 Pa. PUC Lexis 41 (1994)). The OCA believes that the ALJ erred in failing to recommend a sharing of PPL's incentive compensation plans. *Id.*

In its Exceptions, I&E contends that neither the evidence nor the case relied upon by the ALJ supports the recommendation that PPL be permitted to recover the entire incentive compensation program expense from ratepayers. I&E Exc. at 9. I&E argues that while PPL is entitled to recover all reasonably incurred expenses, necessary for the provision of safe, reliable and adequate utility service, it must first satisfy its burden of proof. *Id.* I&E contends that PPL did not meet this burden. I&E opines that, absent sufficient data to determine the relative ratepayer and shareholder values, its proposed equal sharing of the expense is fair because the Company's earnings per share performance and other financial measures directly impact shareholder value, I&E's. *Id.* at 10. I&E also contends that the ALJ erroneously concluded that *Butler Township Water Co. v. Pa. PUC*, 473 A.2d 219 (Pa. Cmwlth. 1984), prohibited, as a matter of law adoption of I&E's proposal to disallow half of PPL's incentive compensation program. *Id.* at 11.

In its Replies to Exceptions, PPL averred that this adjustment would ignore the fact that almost everything PPL does will provide a benefit to both shareholders and ratepayers. PPL R.Exc. at 12. Further, PPL argues that this adjustment is unlawful because a public utility is entitled to recover expenses reasonably necessary to provide service to customers and to earn a fair rate of return. *Id.* A public utility is also entitled to recover operating expenses that are prudently incurred to provide service to customers. *Id.* In *PGW*, *UGI*, and *Roaring Creek*, as cited by the OCA and I&E, incentive compensation was disallowed in total because the utilities could not demonstrate that the program would provide a benefit to ratepayers. *Id.*at 13. In further support of its incentive compensation plan, PPL notes the plan's three overarching objectives: to achieve operational excellence; to optimize workforce readiness and engagement and to increase shareholder value. *Id.*

d. Disposition

We agree with the ALJ's interpretation of *Butler.* We find that, because PPL's incentive compensation plan is reasonable, prudently incurred, and is not excessive in amount, PPL is permitted full recovery of this expense. *See*, *Butler*, 473 A.2d at 221. PPL correctly notes that many of the cases the OCA and I&E rely on are distinguishable from this case because, in those cases there was not adequate evidence that the incentive compensation expense was reasonable or that there was a benefit to ratepayers. *See, Pa. PUC v. Philadelphia Gas Works*, 2007 Pa. PUC Lexis at *73-75; *Pa. PUC v. Roaring Creek Water Co*., 1994 Pa. PUC Lexis at *37-38. Our decision to allow this incentive compensation expense is consistent with our prior decisions approving incentive compensation programs that are focused on improving operational effectiveness. *See, e.g., Pa. PUC v. Aqua Pennsylvania, Inc*., 2008 Pa. PUC Lexis 50 at *24; *Pa. PUC v. Duquesne Light Co*., 1987 Pa. PUC Lexis 342 at *99-100. Accordingly, the exceptions of the OCA and I&E on this issue are denied.

2. PPL Services

a. Environmental Management

i. Positions of the Parties

PPL's FTY claim of $467,000 is based upon the adoption of new federal, state and local environmental regulations that require PPL to undertake greater levels of environmental management activities. More specifically, federal and state environmental rules mandate that routine inspection of storm water and erosion, and sedimentation control measures continue beyond project completion. PPL further asserted that its budgeted increase in construction carries with it an increased need for environmental management services. For these reasons, PPL asserted that the past years' variability of this expense does not support the use of an historic average because, in this instance, the past is not representative of the future. PPL St. 3-R at 2-5; PPL M.B. at 41, 42.

I&E recommended a four-year average of actual annual jurisdictional direct support fees from 2009 through 2011, and the 2012 budget amount, resulting in a ratemaking allowance of $364,000, or a reduction of $103,000 from PPL's FTY claim. It is I&E's position that PPL's claimed level of expense is unsubstantiated. I&E's analysis includes PPL's FTY claim, which I&E believes recognizes an increase over PPL's historic level by giving consideration to the equivalent of 1.5 new full time employees. I&E is also of the opinion that PPL failed to substantiate how new environmental regulations may impact the expenses of operating PPL's distribution system. I&E M.B. at 25-26. I&E further contended that PPL ignored the fact that costs for the implementation of a new software system will not recur, and should not be included within the FTY claim. I&E M.B. at 34.

PPL asserted that I&E's rationale for its proposed disallowance, which relies upon the variability of the expense, the nonrecurring nature of the cost of the new computer system and that PPL does not expect its FTY level of expense to be sustained in subsequent years, was either incorrect or irrelevant, or both. PPL explained that while its expenses for the new software will not extend beyond the FTY, PPL will require additional licenses for employees using the software and additional environmental management support as more employees become authorized to use the software. PPL M.B. at 42. Further, as indicated in the data provided to I&E in response to discovery, PPL's business plan anticipates an increase in environmental management expense as follows: $485,000 for 2013; $494,000 for 2014; $508,000 for 2015; and $549,000 for 2016 and 2017. *Id.* at 43.

ii. ALJ's Recommendation

The ALJ concluded that PPL did not provide citations to the new regulations, nor any specific cost estimates for specific requirements to support its claim that there will be additional costs for environmental compliance. Further, the ALJ found that PPL did not sustain its burden of proving entitlement to the level of support fees sought. In the absence of record evidence to support its claim, the ALJ recommended adoption of I&E's proposal to reduce PPL's FTY claim by $103,000. R.D. at 29-30.

iii. Exceptions

In its Exception, PPL argues that the ALJ's recommendation is in error. PPL claims that, due to the adoption of new regulations, it will be required to undertake greater levels of environmental management activities due to the increase in construction activity throughout its system. This increase in construction activity elevates PPL's expenses related to environmental permitting and the need for additional employees. PPL Exc. at 32.

I&E rejoins that the ALJ correctly rejected PPL's claim for payment to its affiliate for environmental management services and recommended adoption of I&E's $103,000 reduction. I&E argues that PPL's claim contained costs that were irregular, erratic, and unsupported in the FTY. I&E R.Exc. at 9. I&E submits that despite PPL's claims that environmental compliance costs will increase substantially, PPL Corp. contended otherwise in its reports to investors, stating there will be no environmental downside for its distribution system, noting no significant exposure to currently proposed environmental regulations. *Id.* at 10.

iv. Disposition

We agree with I&E and the ALJ on this issue and shall grant the $103,000 expense reduction proposed by I&E. We find that PPL failed to carry its burden of proof that adoption of new regulations will require PPL to undertake greater levels of environmental management activities due to the increase in construction throughout its system. PPL did not refer to any newly adopted environmental regulations to which it is, or will become subject to, in the FTY. Absent this type of support we find the position of I&E to be reasonable. Accordingly, we shall deny PPL's Exception on this issue.

b. External Affairs

i. Positions of the Parties

PPL's budget for 2012 includes $2.602 million for direct services from the External Affairs[6] Department of PPL Services, which is an increase of $1.17 million, or 81% above the $1.432 million 2011 expense. PPL St. 3-R at 6; PPL M.B. at 43. The indirect expenses from this department totaled $1.252 million for the Historical Test Year

[6] External Affairs provides, in part, for the coordination of government relations activities, corporate communications, such as media and public relations services, as well as community and economic development activities. PPL St. 2 at 21-22.

(HTY) and are budgeted at $1.368 million for the FTY. I&E St. 2-SR at 17. The total charges to PPL represent 25% of the annual corporate budget for the HTY and 36% for the FTY. *Id.*

PPL explained that the reason for the increase from 25% to 36% of the annual corporate budget is two-fold. First, a review of the day-to-day activities of the regional community relations directors, who are part of the External Affairs Department, revealed that their activities center around reliability, connections and disconnections, billing and payment, street lighting and requests related to economic development. All of these activities directly benefit PPL, not other members of the PPL corporate system. Therefore, these expenses now are being directly charged to PPL instead of being allocated as indirect charges among all members of the PPL corporate system. Second, PPL stated that increases in line siting and upgrading work, tree trimming and enhanced storm damage communication protocols have also added to the responsibilities of this department. PPL St. 3-R at 6-7; PPL R.B. at 36-37.

I&E contended that the proposed percentage increase would shift an inordinate portion to the rate-regulated entity, PPL, without express consideration of the broader nature of the function of the External Affairs Department. I&E RB at 27. I&E stated that while External Affairs may become involved in billing and connection issues on occasion, PPL has other divisions specifically designed to address these functions on a daily basis. *Id.* at 27-28. In further support of its position, I&E explained that there is very little nexus, if any, between community development activities and the safe and reliable provision of utility service. *Id.* at 28. At a minimum, I&E contended that PPL's efforts with respect to community development enhance the corporate brand at least as much as they affect the provision of electric distribution service. *Id.*

I&E's original recommendation was to allow only the HTY level of directly assigned costs, or $1.432 million representing an expense adjustment of $1.170

million. However, upon review of PPL's explanation of the increase in this cost element from the HTY to the FTY, I&E revised its original expense adjustment. I&E R.B. at 27. I&E's revised expense allowance is based upon an average of the HTY percentage of 25% and the FTY proposed percentage of 36%, for an average of 30.5%. This average percentage, as developed in the table above, was then applied to the total FTY External Affairs Division budget of $10.982 million, providing a recommended allowance of $3.350 million. I&E's revised adjustment, therefore, is $3.970 million - $3.350 million, or $620,000. I&E St. 2-SR at 18.

ii. ALJ's Recommendation

The ALJ found that PPL did not adequately support the proposed increase in its allocated share of the External Affairs Division's FTY budget. The ALJ also found that PPL's only reference was to a schedule attached to its rebuttal testimony. The ALJ recommended that I&E's revised adjustment of $620,000, be adopted based upon I&E's rationale to support its calculated disallowance. R.D. at 31.

iii. Exceptions

In its Exceptions, PPL argues that the Commission should reverse the ALJ and allow the total claim of $2.6 million. PPL Exc. at 33. PPL explains that the increased costs for external affairs is driven primarily by refinements to the process of identifying the affiliates who benefit from the services provided, rather than a dollar increase in the overall costs of those services, which was only 0.8% from 2011 to 2012. *Id*. PPL explains that starting with the FTY, more of the costs for external affairs are directly assigned rather than being allocated as an indirect cost. *Id.* at 34.

In reply, I&E states that PPL provided no evidence to connect monies spent on community and economic development ($865,000 for 2011 and $1.7 million for 2012) and government relations ($463,000 for 2011 and $727,000 for 2012) to the provision of safe and reliable utility service. I&E R.Exc. at 10; I&E Exh. No. 2, Schedule 13, at 2. I&E also states that while logic dictated that as the allocation of direct costs rose, the allocation of indirect costs should have decreased, because overall expenses of PPL Services for this account increased by only 0.8% I&E R.Exc. at 11.

iv. Disposition

Based upon our review of the record evidence, we shall reverse the ALJ's recommendation on this issue. I&E's position is based upon its opinion that this expense lacks any nexus to PPL's provision of safe and reliable utility service and that the proposed percentage increase would shift an inordinate portion to the rate-regulated entity, PPL, without express consideration of the broader nature of the function of the External Affairs Department. I&E has also taken the position that since there was a very small increase in the total expense, the significant rise in direct expenses should have caused the indirect expense allocation to shrink. As shown in the table above, the allocated indirect costs increased from 2011 to the FTY by 9.2%, or $116,000, while the total indirect and other expenses to be allocated increased by 75.0%, or $21.951 million.

PPL Exhibit DAC-1, Schedule 4, page 2, indicates that the indirect and other costs to be allocated increased from $29.241 million to $51.192 million from 2011 to the FTY. The $29.241 includes a Storm Insurance recovery of $15.501 million. Without this significant insurance recovery, the increase in this account would be only 14% or $6.45 million. I&E did not present any issue regarding the amount of indirect and other costs to be allocated until after it adopted PPL's explanation for the increase in direct assignment of costs relative to this account.

I&E's final position is to 'split the baby' by taking an average percentage of the jurisdictional expense level for 2011 and the FTY, as they are compared with the total amount of expense as shown in the table above. We believe that this mathematical adjustment is not supported by I&E's contentions of an insufficient nexus or that the percentage increase in the direct assignment portion represents an excessive shift of expense to PPL, the regulated entity. Accordingly, we shall grant PPL's Exception and reverse the ALJ's recommendation on this issue.

c. Office of General Counsel

i. Positions of the Parties

Legal services to PPL Electric are provided by PPL Corporation's Office of General Counsel (OGC), and PPL's jurisdictional FTY claim for OGC is $6.083 million. I&E Exh. 2, Sch. 17 p. 2. According to I&E, PPL's claim is based on its HTY expense increased by $1.2 million in estimated costs for outside counsel fees related to this proceeding. Because of this, I&E recommended a ratemaking allowance of $4.833 million for OGC expense, which is a $1.2 million reduction to PPL's claim. The basis for I&E's adjustment is to eliminate the additional expense associated with outside counsel for this proceeding since the Company also includes a claim for rate case expense in its pro forma adjustments. I&E M.B. at 38.

PPL agreed with the adjustment but argued that it was more appropriate to eliminate the duplication from O&M expenses because the expense in question will be incurred by the OGC and then charged directly to PPL. PPL St. 8-R, at 41-42. PPL M.B. at 47.

I&E acknowledged PPL's acceptance of the expense reduction, but contended that it is appropriate to reflect the reduction as a part of the affiliate support allocation, and not as a rate case expense reduction. I&E M.B. at 39. I&E explained that keeping the expense as a part of PPL's affiliate support allocation will overstate the level of OGC affiliate support dedicated to the provision of electric distribution service in years when there is no rate case. *Id.* In other words, ratepayers will be allocated an inflated portion of OGC expenses based upon rate proceeding expenses that are not provided annually or regularly by OGC. *Id.* Further, the overstated level of OGC affiliate support allocated to PPL in this proceeding will then be used in future proceedings to support similarly overstated OGC allocations. *Id.*

ii. ALJ's Recommendation

The ALJ found merit in I&E's rationale and recommended that in order to prevent the overstatement of legal expenses in non-rate case years, this reduction should be to the Affiliate Support (Direct) – Office of General Counsel expense claim. R.D. at 32.

iii. Exceptions

Exceptions were not filed by the Parties on this issue.

iv. Disposition

Finding it otherwise reasonable, we will adopt the recommendation of the ALJ. However**,** some accounting clarification is in order.

In PPL's Exhibit Future 1-Revised, Sch. D-6, an adjustment was made to O&M expenses to reflect its revision to rate case expense. In rebuttal testimony, PPL explained its adjustment. The original rate case expense claim of $2.025 million was normalized over a two-year period, providing for an annual expense of $1.013 million. Based upon opposing testimony, PPL revised this claim by removing the remaining $674,000, representing its 2010 rate case expense, and by $1.2 million, representing a duplicate entry. The $1.2 million was budgeted by the OGC for this proceeding. PPL St. 8-R at 42. With these two adjustments, PPL's original O&M expense claim of $1.687 million was revised to be a reduction to FTY O&M of $0.861 million. Based upon these two adjustments, which include rate case expense and a direct assignment of cost from the OGC, PPL's reduction to its collective O&M expenses for the FTY would appear to be properly reflected in Exhibit Future 1-Revised.[7]

The adjustment proposed by I&E and recommended by the ALJ to reduce the OGC allocated expense and to leave the $1.2 million in rate case expense will not change the outcome of the revenue allowance in this proceeding. This proposed change would effectively reverse the decrease in rate case expense already included by PPL in its Future 1-Revised by $1.2 million and reduce the OGC expense by that same amount. The impact would be an increase in rate case expense of $1.2 million and a decrease in OGC expense of $1.2 million.

Accordingly, we shall adopt the recommendation of the ALJ on this issue.

3. Storm Damage Expense Recovery

i. Positions of the Parties

PPL revised its total storm damage expense recovery claim due to the unavailability of insurance beyond the FTY. PPL Exc. at 20-26. PPL stated that without storm damage insurance, PPL's initial FTY expense claim as it related to insurance is moot. PPL's revised FTY storm damage expense of $23.199 million includes the following: $17.875 million for annual storm damage expenses and a proposal to amortize over five years the extraordinary storm expenses in excess of insurance recoveries of $26.620 million incurred during major storms in August 2011, Hurricane Irene, and October 2011 at $5.324 million per year for five years. PPL Exc. at 24-25; PPL Exh. GLB-9.

---

7 *See*, Exhibit Future 1-Revised, Schedule D-6.

PPL stated that among the details to be agreed upon before a rider may become effective are (1) provisions for interest on under and over collections; (2) timing of reconciliation; (3) reporting of storm damage expenses and revenue for their recovery; (4) methods for adjusting the annual level of the expense in rates; and (5) exact categories of storm damage expense that would be subject to the reconciliation. PPL M.B. at 71.

I&E recommended a simple five year average of total storm damage expenses, which would account for yearly fluctuations to determine an appropriate level of expense for ratemaking purposes. I&E's calculated five-year average of PPL's storm expenses from 2009 to 2011 inclusive is $23.785 million. I&E St. 2 at 35. I&E also recommended that PPL establish either a reserve account or a rider to recover storm damage expenses. I&E St. 2-SSR at 4-5.

ii. ALJ's Recommendation

The ALJ recommended that PPL be directed to establish a storm damage reserve account, as proposed by I&E, to be submitted to the Commission for approval. R.D. at 39. If approved by the Commission, the ALJ found that the reserve account should be implemented when the insurance coverage provided by PPL's present provider expires. The ALJ also recommended that the statutory advocates be included in the development of this storm damage reserve account. R.D. at 39. The ALJ also approved PPL's original storm damage expense claim of $26.699 million, which includes $12.625 million for annual storm damage expenses not covered by insurance, $8.75 million for insurance premiums and a five-year $5.324 million amortization of PPL's 2011 extraordinary storm damage expense claim.

iii. Exceptions

In its Exceptions, PPL supports the ALJ's recommendation to establish a reserve/tracker mechanism with reconciliation for over and under collections. PPL states that it intends to propose such a mechanism in a filing to be made as soon after the Commission decision in this proceeding as practicable. PPL will request that the proposal be given expedited consideration so that it can become effective at the earliest possible date. PPL Exc. at 23. PPL also revised its expense claim because it will be unable to purchase insurance beyond 2012. PPL Exc. at 24-26. PPL's revised claim is comprised of $12.625 million for expected storm damage not covered by current insurance; $5.25 million for the normal ongoing level of storm damage previously covered by insurance beyond 2012; and a five-year amortization of $5.324 million for the extraordinary loss incurred in 2011, for a total revised expense claim of $23.199 million.

In reply, I&E encourages the Commission to require PPL to meet with the statutory advocates to develop a rider within ninety days of Order entry. I&E R.Exc. at 13.

iv. Disposition

Based upon our review of the record and the Parties' Exceptions and Replies to this issue, we agree with the ALJ's recommendation to adopt I&E's proposal for PPL to propose a Storm Damage Expense Rider for Commission review. R.D. at 39. The issues to be discussed between PPL and the public advocates shall include, but not be limited to, the following: (1) provisions for interest on under and over collections; (2) timing of reconciliation; (3) reporting of storm damage expenses and revenue for their recovery; (4) methods for adjusting the annual level of the expense in rates; and (5) exact categories of storm damage expense that would be subject to the reconciliation. Additionally, we approve I&E's recommendation, and so direct, that PPL file a rider for storm damage expense recovery within ninety days of the date of entry of this Opinion and Order. PPL has stated its intention to file as soon as practicable after the Commission's entry of a final decision in this proceeding.

Recovery of PPL's revised FTY storm damage expenses of $23.199 million shall be through base rates. Any recovery through a Storm Damage Rider shall be permitted only to the extent that such expense exceeds the amount included within base rates.

4. Payroll - Employee Complement

i. Positions of the Parties

PPL has proposed a budget for payroll based upon an employee complement of 2,002, which it states is necessary for the management and maintenance of the Company's transmission and distribution systems in order to meet the needs of customers. PPL St. 2-R at 8-9; PPL M.B. at 71.

The OCA has proposed reducing the payroll budget to allow for an employee complement of 1,943, which is PPL's average number of employees over the sixteen-month period prior to March 2012. OCA M.B at 18. The OCA's proposal would reduce PPL's FTY wages, payroll taxes and benefits by $3.740 million. OCA St. 1-REV at 17. In response, PPL asserted that it is in the process of filling 106 positions. PPL St. 2-R at 8; PPL M.B. at 72.

The OCA argued that the budgeted staff levels should be reasonably based on historic data. *See e.g., Pa. PUC v. PPL Gas Utilities Corporation,* 255 P.U.R. 4th 209, 242 (Pa. PUC 2007) (utility's complement claim was reasonable and supported by the record where at times the actual number of employees was greater than budgeted, because the number was supported by historic data). OCA M.B. at 18. The OCA also noted that PPL's employee complement had declined from 1,974 in December 2010, to 1,943 in June 2012. OCA M.B. at 19. Thus, it is the OCA's opinion that since PPL had neither claimed nor proven that the lower complement had resulted in inadequate service, there is no evidence of record to support a need for the higher number of employees. OCA M.B. at 19.

ii. ALJ's Recommendation

The ALJ took notice that PPL's actual employee complement for the first three months of the FTY was, on average, seventy-one employees less than budgeted and that, as of June 2012, the Company's complement was 1,942, which was still one person lower than the OCA recommendation. OCA R.B. at 6. However, the ALJ found that PPL is most familiar with its own needs in terms of staffing, and that PPL's historical payroll supports a finding that the Company's claim is reasonable. R.D. at 41. Accordingly, the ALJ rejected the OCA's adjustment and recommended adoption of PPL's employee complement. *Id.*

iii. Exceptions

In its Exceptions, the OCA states that the ALJ erred in granting PPL's employee complement of 2,002 because, according to the OCA, it is not supported by the record. OCA Exc. at 9. The OCA further asserts that it is unlikely that PPL's complement will increase by three percent to achieve the budgeted 2,002 employee level by December 31, 2012. *Id.*at 11.

PPL replies that the OCA failed to recognize the appropriate level of staffing needed to maintain and manage PPL's system and instead relied upon a sixteen-month average complement ending March 2012 as the basis for its adjustment. PPL R.Exc. at 15.

iv. Disposition

We agree with the ALJ that PPL is most familiar with its needs in terms of staffing, and that PPL's historical payroll supports a finding that the Company's claim is reasonable. Further, we believe that the basis for the OCA's adjustment, while mathematically accurate, does not envision an appropriate level of staff needed to maintain and manage PPL's system. Accordingly, we shall deny the OCA's Exception on this issue.

5. Uncollectible Expenses

i. Positions of the Parties

PPL's total FTY uncollectible accounts percentage is 2.23%, representing an expense of $42.099 million. This amount includes expected write-offs plus any change in the reserve for doubtful accounts due to increased accounts receivable, which are subject to write-off. PPL M.B. at 72.

I&E's position is that PPL's proposed reserve allowance for uncollectible accounts expense should be rejected because that methodology is subject to manipulation and does not reflect PPL's actual expense or historic percentage write-off factor. I&E St. 2 at 5-6. Further, I&E stated that the Commission has no authority to permit recovery of hypothetical expenses not actually incurred by PPL, pursuant to *Barasch v. Pa. PUC,* 493 A.2d 653, 655 (Pa. 1985):

> Although the Commission is vested with broad discretion in determining what expenses incurred by a utility may be charged to the ratepayers, the Commission has no authority to permit, in the rate-making process, the inclusion of hypothetical expenses not actually incurred. When it does so,

as it did in this case, it is an error of law subject to reversal on appeal.

I&E's analysis presents PPL's actual net write-off uncollectible percentages from 2007 to 2011, which is based upon the following data supplied by PPL in response to interrogatory I&E-RE-10:

Actual Net Write-Off Uncollectible Percent				
2007	↑ 2008	↓ 2009	↓ 2010	↑ 2011
1.57%	1.72%	1.63%	1.49%	1.97%

I&E Exh. No. 2, Sch. 1 and 2; I&E MB at 22. Additionally, I&E stated that its analysis clearly showed that PPL's proposed 2.23% write-off factor is unsupported by record evidence. I&E notes that in determining the Purchase of Receivables program administrative factor percentage in PPL's 2010 base rate case, the ALJ found that use of a five-year average, as proposed by I&E here, is appropriate. *Id.* at 23 (citing *Pa. PUC v. PPL Electric Utilities Corporation,* Docket No. R-2010-2161694 (Order entered December 16, 2010)).

ii. ALJ's Recommendation

The ALJ concluded that PPL's use of a FTY permits forecasting in terms of using real data to forecast the final uncollectibles for 2012, which is sufficient to ensure that the Company's uncollectibles will be covered. Doubtful accounts, however, present an unmeasurable, and unsupported, factor which the ALJ disallowed. R.D. at 42.

I&E used five years of data in its calculation, which includes four years of recession and two years post-rate cap. The final I&E recommendation is based on the 2009-2011 three-year average, which is confirmed by I&E's five-year average, each yielding a 1.70% uncollectible rate. The ALJ stated that it is evident that the highest historic percentage of uncollectible accounts between 2007 and 2011 is below PPL's requested 2.23% recovery rate. Further, the ALJ found that PPL's proposed increase in the uncollectible rate is unjustified. Accordingly, the ALJ found that the methodology and result proposed by I&E is reasonable and should be adopted by the Commission.

iii. Exceptions

In its Exceptions, PPL states that an historic three-year average, as proposed by I&E and recommended for approval by the ALJ, is not appropriate because it is inconsistent with the ongoing increase in write-offs over the last three years and because the three-year average is inconsistent with actual, current data. PPL Exc. at 30. PPL explains that the goal in this proceeding should be to set rates which reasonably reflect future conditions. The three-year average relied upon by the ALJ included 2009, when PPL's generation supply rates were capped. Since then, PPL's electric supply rates for provider-of-last-resort service have increased significantly, when compared to prior periods where the generation supply rate cap was in effect. Not surprisingly, PPL experienced increases in the number and dollar amounts of uncollectible accounts since the generation rate cap has ended. *Id.* In addition, PPL and its customers continue to experience the effects of the recession. *Id.* PPL, therefore, asserts that the unfavorable economic conditions adversely affect uncollectible accounts expense and the use of a three-year average where uncollectible accounts expenses are increasing will, by definition, understate current costs. Accordingly, PPL believes that there is no basis for using a three-year history to calculate PPL's FTY uncollectible accounts allowance. *Id.* Lastly, PPL excepts to the ALJ's disallowance of its proposed increase in bad debt reserve. PPL states that elimination of this adjustment would be improper because the reserve includes charges for the increase in accounts receivable that are subject to eventual write-off. *Id.* at 31.

In reply, I&E contends that PPL ignores the facts, cited by the ALJ, that the five-year average, commencing in 2007 and extending through 2011, includes not only two years of data following removal of the generation rate cap (2010 and 2011), but also four years of data from the continuing recession (2008, 2009, 2010, and 2011). I&E R.Exc. at 6-7. I&E believes that while citing an increase in the number of accounts and uncollectible dollars from 2009 through 2011, PPL has misconstrued those facts to claim there is an ongoing increase over the last three years. I&E R.Exc. at 7.

I&E also contends that the facts do not support PPL's claimed 2.23% uncollectible accounts expense rate unless the Commission looks at only a snapshot of six months of experience in the first part of the FTY and then extrapolates that to an assumed level. I&E R.Exc. at 7. However, I&E notes that this Commission has never calculated an allowed uncollectibles expense rate on this basis. *Id.* Further, I&E claims that its calculation comports with the Commission's Regulations, the Company's own calculation of other claims, and PPL's calculation of its uncollectibles expense in both its 1985 and 2010 rate cases. *Id.* I&E submits that PPL's claims that the ALJ's allowance understates PPL's experience and that a three-year average fails to reflect ongoing increases is inaccurate. *Id.*

iv. Disposition

Based upon our review of the record evidence, the ALJ's recommendation and the Exceptions and Replies filed thereto, we shall adopt PPL's position on this issue as it reflects the level of uncollectible accounts on a going forward basis. In this proceeding, a FTY is the basis for ongoing utility expenses. We believe that I&E's historic analysis, although used by the Commission in prior decisions, is not warranted in this instance as it will not reasonably reflect future conditions. Accordingly, we shall deny I&E's Exception on this issue.

6. Revised Rate Case Expense and Normalization Period

i. Positions of the Parties

PPL's original rate case expense of $1.687 million for the FTY was comprised of $2.025 million for the instant proceeding and $674,000 as an amortization recovery of its 2010 base rate case expense. PPL proposed to recover the $2.025 million over a two-year period, or $1.013 million per year. This two-year normalized amount of $1.013 million plus the amortization portion of $674,000, totaled $1.687 million. Subsequently, PPL revised its rate case expense claim to remove its proposed amortization expense of $674,000 and $1.2 million, which PPL inadvertently included in both rate case expense and PPL Services-Office of General Counsel. These two adjustments have been reflected in PPL Exhibit Future 1-Revised, Schedule D-6, and result in a reduction to O&M expense of $861,000.

PPL proposed a two-year normalization period to recover the rate case expense associated with the instant proceeding and argued that a two-year recovery period was appropriate given the pressure that its capital spending program will place on earnings. PPL's planned rate base capital expenditures of approximately $1.7 billion over the next two calendar years represent an increase in PPL's total net measure of value as of December 31, 2012, exceeding fifty percent. PPL MB at 76. PPL asserted that with such a significant capital investment over the next two years, it seems more likely than not that its next base rate case could be filed during or before 2014. Further, PPL stated that even though it may request a distribution system improvement charge (DSIC), that mechanism is capped at five percent of revenue, which would do little to offset the incremental revenue requirement associated with the significant investment in rate base projected over the next two years. For these reasons, PPL believes that a two-year normalization of rate case expense is appropriate. *Id.*

The OCA advocates using a three-year period because PPL's last three rate cases filed in 2004, 2007, and 2010, were held exactly three years apart. The OCA's position is that it is the historical filings, not the actual intentions of the utility, which will guide the determination of the normalization period. OCA M.B. at 26. (citing *Pa. PUC v. City of Lancaster,* Docket No. R-2010-2179103 (Order entered July 14, 2011); *Pa. PUC v. Metropolitan Edison Company,* Docket No. R-00061366 (Order entered January 4, 2007)).

I&E agreed that the normalization period should be determined by the historical filings and, accordingly, recommended a thirty-two month normalization period based upon PPL's last four base rate filings.

Thus, I&E's recommended allowance for expenses associated with the instant rate proceeding is $759,375. This is calculated by dividing PPL's $2.025 million rate case expense claim by thirty-two months and then multiplying the result by twelve months to arrive at a normalized level of expense. [$2,025,000 / 32 months = $63,281.25; $63,281.25 x 12 months = $759,375] This reduces PPL's FTY claim by $253,625. ($1,013,000 - $759,375 = $253,625).

ii. ALJ's Recommendation

PPL has agreed to two adjustments regarding its claimed rate case expense. First, PPL has removed the prior base rate expense claim of $647,000 from its FTY total. Second, PPL has removed from total FTY expenses the $1.2 million double count of rate case expense as described above.

As discussed above,[8] the ALJ recommended the double count of $1.2 million of legal fees included by PPL in both its rate case expense claim and its PPL Services-OGC, be removed from the PPL Services expense and not the rate case expense as requested by PPL.

Regarding the normalized recovery period for allowable rate case expense, the ALJ found that the OCA and I&E used the appropriate historic analysis methodology. The ALJ found I&E's analysis to be more accurate because it used the filing date of each of the last four base rate cases to develop a normalized period reflective of PPL's actual base rate filing frequency. Therefore, the ALJ recommended adoption of I&E's thirty-two month recovery period.

iii. Exceptions

In its Exceptions, PPL notes that in late 2008, it conducted a comprehensive study to assess the age, condition and performance of plant in order to develop a strategy for capital replacements in order to avoid the cost and reliability of service effects of aging infrastructure. Based on this study, PPL embarked on a ten-year capital plan to replace, maintain and improve plant and anticipates adding $1.6 billion in plant from 2012 through 2016. Rate case history prior to 2010 does not reflect this construction program. PPL believes that plant expenditures of this magnitude will necessitate a base rate case within two years, if not sooner. Based upon PPL's capital improvement plan, PPL also believes it is unreasonable to rely on an historic pattern of rate cases that extends back eight years to 2004 to determine the appropriate period for normalization of rate case expenses. PPL Exc. at 35.

In reply, I&E states that citing no error by the ALJ, PPL repeats the same argument rejected by the ALJ, namely, that because of infrastructure plans, rate case

---

[8] See discussion in the Office of General Counsel section above.

history prior to 2010 is not an accurate reflection of the Company's future rate case plans. I&E R.Exc. at 8.

I&E explains that the law is well-settled that, absent exceptional circumstances, rate case expense is normalized based upon a party's filing history and not its presently stated intentions, no matter how unequivocally declared. *Id.* (citing *Popowsky v. Pa. PUC*, 674 A.2d 1149, 1154 (Pa. Cmwlth. 1996); *Pa. P.U.C. v. Borough of Media Water Works*, 72 Pa. P.U.C. 144 (1990)). I&E believes that there are no exceptional circumstances here. Conversely, I&E asserts that there are mitigating circumstances in the form of the effect of the DSIC. *Id.*

I&E contends that PPL has been finely attuned to its infrastructure needs since 2004 when it began regularly filing rate cases and, contrary to PPL's characterization, the current infrastructure improvement plan is not a sudden development that renders its recent rate case history irrelevant. *Id.* I&E notes that, recently, the Commission rejected a similar argument in which the Borough of Quakertown disputed a seven-year normalization based on filing history because anticipated intensive capital construction was under contract and had broken ground with an estimated 2013 completion date. *Id.* In affirming the ALJ, the Commission found that if the Borough filed sooner it "may be appropriate to consider a shorter normalization period going forward." *Id.* (citing *Pa. PUC v. Borough of Quakertown*, Docket No. R-2011-2251181 (Order entered September 13, 2012)).

iv. Disposition

Based upon our review of the record established in this proceeding, the ALJ's recommendation, the Exceptions and the Replies filed thereto, we shall reverse the ALJ and grant the Exception of PPL on this issue. As previously discussed, this proceeding is premised upon a FTY and, based upon that criterion, certain expenses may now be based upon future expectations. We believe that the normalization period for rate case expense is one of those expenses. We fully support PPL's capital expenditure program and expect that it will proceed into the future as explained by PPL. Further, we can reasonably expect that PPL will file its next base rate case much closer to a twenty-four month interval than to a thirty-two month interval as proposed by I&E and the OCA. Accordingly, we shall grant the exceptions of PPL on this issue.

7. CEO's Proposed Increase in LIURP Funding

i. Positions of the Parties

PPL has proposed no changes in its universal service programs (USPs) nor to the funding for them, as these are subject to separate proceedings. *PPL Electric Utilities Corporation Universal Service and Energy Conservation Plan for 2011-2013,* Docket No. M-2010-2179796 (Order entered May 5, 2011). This was a litigated proceeding, with the participation of interested parties.

PPL's USPs include OnTrack (PPL's customer assistance program), WRAP (PPL's free weatherization program or Low Income Usage Reduction Program), Operation Help (PPL's hardship fund for customers with incomes at or below 200 percent of the federal poverty level, and CARES (PPL's Customer Assistance and Referral Evaluation Services, which connects customers with local community based organizations offering short-term help to customers at or below 200 percent of the federal poverty level). PPL St. 9 at 3-4.

PPL's currently effective USPs were approved by Commission Order entered May 5, 2011, at Docket No. M-2010-2179796, and run through December 2013. In June 2013, PPL will submit to the Commission for review and approval its USP plan for years 2014 through 2016, and will include therein proposals for any necessary or appropriate changes to the current programs and services available to low-income customers. PPL M.B. at 77.

CEO argued that PPL's last increase of $250,000 in the 2011-2013 USP case was inadequate to serve the needs of the low-income customer base and suggests that funding increase from $8.0 million to $9.5 million for PPL's WRAP Program. CEO disagreed with PPL's position that a base rate case is not the proper place for this argument, citing former rate cases that have evaluated the low-income plan budgets.

CEO pointed out that the funding for WRAP increased only 3% in the USP case, which translates into an additional 106 customers per year at the average cost of $2,349, an increase not consistent with the increased number of low income customers in PPL Electric's territory, which CEO argues is 44% based on the 2008 census. CEO M.B. at 5; CEO St. 1 at 7. CEO continues that the usefulness of a well-funded LIURP program has long been recognized by the Commission as a tool for lowering heating bills, thus creating a heating bill that the customer is more likely to pay. CEO M.B. at 5-6. In addition, CEO states that the higher prices resulting from this proceeding will be effective January 1, 2013, a full year prior to the end of the effective period from the current USP case. CEO R.B. at 2. It is CEO's opinion that refraining from addressing this issue now will deprive low-income customers of timely relief from a rate increase. CEO R.B. at 3.

PPL countered that the increase in low-income customers in its service territory should not be viewed in isolation. Rather, consideration needs to be given to the cost impact on other residential customers, the ability of the community based organizations (CBOs), which administer the programs, to deliver additional services, and the availability of funding from other sources. PPL advocated for the consideration of all of these issues within the triennial filings for approval of the plans themselves, where all entities involved may participate. PPL St. 9-R at 6; PPL M.B. at 79.

I&E opposed CEO's proposal because it fails to consider the total increase in the funding of universal service benefits in recent years. Since 2004, over three base rate cases, the funding for the OnTrack program increased from $9.5 million to $41.2 million, and from 2000 to 2008, weatherization funding grew from $5.7 million to $8 million. I&E M.B. at 66-67. I&E stated the following:

> Through 2012 PPL ratepayers will be compelled to contribute $75.35 million annually to the funding of PPL's USP benefits. That mandatory ratepayer funding is projected to increase to $78 million by 2014. The trajectory of mandatory ratepayer funding of PPL's universal service benefits has skyrocketed upward, increasing 122% from 2008 to 2011 and projected to increase by 145% through 2014. I&E submits that PPL's ratepayers are contributing sufficiently towards relief for their low-income neighbors. PPL's LIURP funding should remain at its current $8 million.

I&E M.B. at 68.

ii. ALJ's Recommendation

The ALJ found that base rate cases are the traditional forum for budgets of low-income plans, but in recent years, the Commission has required companies to file separate cases to address the USP budgets. R.D. at 44-45. PPL has a Commission-approved plan in place, including a budget. R.D. at 45.

The ALJ continued by observing that the USPs for EDCs, including PPL, are filed every three years and concentrate on the programs included in the customer assistance portfolio. After noting that, in a base rate case, any part of the Company's tariff may be brought into question, the ALJ stated that as an issue raised by another party, the burden of proving that the universal service issues deserve additional funding belongs to the party raising it – here, CEO. *Id.*

The ALJ concluded that the Commission's institution of separate proceedings for these plans is indicative of a preference to address the issues within those proceedings. Therefore, the ALJ recommended that CEO's proposed increase in funding be denied. However, the ALJ encouraged CEO to participate in the triennial plan reviews. *Id.* at 46.

iii. Exceptions

In its Exceptions, CEO submits that the Commission has a statutory duty to ensure that a company's USPs are appropriately funded and available. Further, CEO contends that a proceeding that results in a rate increase to low-income customers would require the Commission to determine the effect of the rate increase on whether those USPSs are, or remain, appropriately funded and available. CEO Exc. at 6. CEO alleges that to postpone consideration of universal service funding to a time after a rate increase takes effect, and to a non-adversarial proceeding, is contrary to the Commission's past practice and its statutory duty. *Id.*

PPL responds that the ALJ properly rejected CEO's proposal because the USP costs are no longer recovered through base rates. PPL R.Exc. at 22-23. I&E also supports the ALJ's recommendation on this issue. I&E R.Exc. at 14-15.

iv. Disposition

We agree with the ALJ, PPL and I&E on this issue. Recent Commission practice is to address all aspects of USPs through the triennial filing process and to collect all revenues through a rider to base rates. We believe this process has provided, and will continue to provide, the customers who rely upon USPs with appropriate funding levels on a timely basis. Accordingly, we deny the Exceptions of CEO on this issue.

8. Consumer Education Expenses

i. Positions of the Parties

PPL's consumer education program was mandated and authorized by the Commission's Final Order in *PPL Electric Utilities Corporation Consumer Education Plan for 2008-2012,* Docket No. M-2008-2032279 (Order entered July 18, 2008), which was designed to communicate Energy Education Standards to customers. The goal was to educate consumers in each EDC's service territory regarding (1) the expiration of rate caps; (2) ways to reduce energy consumption and, thereby, lower bills; and (3) the availability of retail competition.

PPL's FTY consumer education expense claim of $7.976 million is comprised of $5.482 million associated with the final year of PPL's Commission-approved Consumer Education Plan (CEP), plus $2.494 million for three Retail Markets Investigation (RMI) mailings and customer protections regarding the Eligible Customer List (ECL), which PPL proposed to collect through a CER. PPL St. 5-R at 28-29.

I&E and the OCA opposed portions of PPL's proposal. I&E pointed out that PPL's proposed CER is designed to recover costs of the RMI initiatives, and that any costs related to education regarding those initiatives should be recovered through that rider and not included in base rates. While I&E does not object to recovery of the Commission mandated RMI costs and costs related to the ECL mailings, it notes that these should be recovered under the CER, if it is approved, and removed from base rates. I&E points out that the Commission and its EDCs are moving into the next phase of retail competition and that shopping and energy efficiency are more effectively addressed by the Act 129 Energy Efficiency and Conservation (EE&C) Plan and the RMI mandates. These are funded through the Act 129 Rider and the proposed CER. I&E St. 2 at 44; I&E M.B. at 62-63.

The OCA recommends that the Company's consumer education funding be set at $5,400,000, annually, based on the budget amount approved in the 2008-2012 Consumer Education Plan. OCA MB at 29.

ii. ALJ's Recommendation

The ALJ found that the Commission's mandates must be funded, and the issue here is the best method of funding. While PPL must be reimbursed fully for its prudent expense, there must be a limit to the amount that should be spent. The ALJ concluded that the I&E proposal to recover the costs through a CER is the best choice, as it fully funds the Commission's mandates but does not waste ratepayer money on duplication.

Accordingly, the ALJ recommended that funding for PPL's CEP lapse at the end of the FTY and that the education costs of $2.494 million incurred in carrying out the RMI mandates be recovered using the CER and, thus, removed from the allowed increase in base rates associated with this proceeding. R.D. at 49.

iii. Exceptions

In its Exception, PPL explains that the ALJ would disallow complete recovery of costs associated with PPL's Commission-approved Consumer Education Plan, which promotes and encourages the competitive retail market for electric generation in PPL's service territory and encourages conservation, beyond 2012. PPL Exc. at 26. The issue presented here, as viewed by PPL, is whether the Commission recognizes the need for the Energy Education Standards established in the Commission's Final Order on *Policies to Mitigate Potential Electricity Price Increases*, at Docket No. M-00061957, and wants the Consumer Education Plan to continue. According to PPL, if the Plan is to continue, the Commission should approve PPL's claim of $5.482 million for that Plan, in addition to other consumer education expenses. If not, PPL states that the ALJ's recommendation should be adopted on this issue, and PPL will discontinue the program. *Id.*

I&E rejoins that despite PPL's assertion otherwise, the Act 129 Plan provides both financial incentives as well as education about energy efficiency, rendering the CEP duplicative. *See* I&E St. 2-SR at 47-48, citing PPL's *Final Report for Year 2 of PPL Electric Utilities Corporation's Act 129 Plan,* at Docket No. M-2009-2093216. I&E R.Exc. at 14. In addition, I&E states that while the specific activities and programs may differ, the goals under all of these programs are the same: (1) to educate customers about shopping and efficiency; and (2) to provide financial incentives to modify behavior. Accordingly, I&E continues to urge that PPL's five-year plan and its $5.4 million annual cost should be allowed to lapse naturally at the end of year 2012. *Id.*

iv. Disposition

As discussed above, we agree that Commission mandates must be funded. With regard to the recovery of Act 129 costs, we believe that it is proper to recover these costs through a rider to base rates. It is unknown whether the Act 129 expenses discussed in this section will be in place for many years or for only a few years, which supports recovery through a rider to base rates. Accordingly, we shall approve the education costs incurred in carrying out RMI mandates as expenses to be recovered through the CER Rider.

Regarding continued recovery of PPL's CEP costs of $5.482 million, we find that the record supports allowing these pre-Act 129 expenses to lapse at the end of the FTY. Accordingly, we shall deny the Exceptions of PPL on this issue and reduce PPL's O&M expenses by $5.482 million.

9. CAP (Customer Assistance Program) Outreach

i. Positions of the Parties

In its Exceptions, the OCA states that the ALJ did not address its recommendations regarding CAP outreach initiatives. OCA Exc. at 12-13. The OCA proposed three specific outreach initiatives: (1) that PPL engage in a direct-contact outreach program aimed at a population of customers that are both confirmed low-income and 120 days or more in arrears; (2) that all shut-off notices to confirmed low-income customers be modified so that they also contain a notice of CAP availability and the means of accessing CAP; and (3) that PPL engage in a direct-contact outreach program focused on customers 120 days or more in arrears whether or not those customers are confirmed low-income customers. OCA St. 4 at 33-34; OCB M.B. at 115.

PPL noted that it is not opposed to modifying its termination notice to include information about CAP so long as it does not add another page to the termination notice because that would increase the cost. PPL St. 9-R at 22. Further, PPL would not consider a requirement to have two separate termination notices, one for confirmed low-income customers and one all other residential customers. *Id.* at 23. PPL further stated that it is willing to propose the content and format of the new information on the termination notice and review it with Commission staff and interested Parties. *Id.*

Regarding the OCA's first and third recommendations, PPL states that these should not be adopted. PPL asserts that its current outreach programs are sufficient and that the OCA has not provided evidence that more outreach is needed to contact confirmed low-income customers who are 120 days or more in arrears. PPL St. 9-R at 22. Further, most residential customers with overdue balances or terminated accounts call PPL to address their concerns. *Id.* at 23. Depending on a customers' status in the collection process, PPL has concerns about sending them a mixed messages regarding the requirements stated in the collection notices versus the content of the targeted outreach. *Id.* at 23-24.

ii. ALJ's Recommendation

As noted by the OCA, the ALJ's Recommended Decision did not address this issue.

iii. Disposition

Based upon the testimony of the Parties, we shall grant the OCA's Exception, in part, with regard to its second recommendation that shut off notices to confirmed low income customers include information about CAP. However, we expressly acknowledge and accept PPL's willingness to propose the content and format of the new information on the termination notice and review it with Commission Staff and interested Parties. We encourage PPL to proceed in a timely manner, in this regard. Further, PPL should submit its proposed content and format of the new notice to the OCA and the Commission's Bureau of Consumer Services for review. Lastly, we agree with PPL that their current outreach programs, as discussed in testimony, are well designed and that the OCA has not provided sufficient evidence to support its first and third recommendations. Accordingly, we shall grant the OCA's exception in part, as discussed above.

E. Rate of Return

1. Introduction

The overall rate of return position of the Parties in this proceeding is summarized in the following tables:

PPL

Capital Type	Percent of Total %	Cost Rate %	Weighted Cost %
Debt	48.98	5.58	2.73
Common Equity	51.02	11.25	5.74
Total	100		8.47

PPL St. 11, Exh. PRM-1, Sch. 1.

PPL modified its overall return to reflect the actual issuance of $250 million of long-term debt on August 24, 2012, at an interest rate of 2.61%. This update resulted in the following revised rate of return position of PPL:

PPL Revised

Capital Type	Percent of Total %	Cost Rate %	Weighted Cost %
Debt	49.22	5.50	2.71
Common Equity	50.78	11.25	5.71
Total	100		8.42

PPL M.B. at 91.

OCA

Capital Type	Percent of Total %	Cost Rate %	Weighted Cost %
Debt	52.84	5.58	2.95
Common Equity	47.16	9.00	4.24
Total	100		7.19

OCA St. 2, Exh. SGH-1, Sch. 11 at 1.

I&E

Capital Type	Percent of Total %	Cost Rate %	Weighted Cost %
Debt	54.89	5.58	3.07
Common Equity	45.11	8.38	3.77
Total	100		6.84

I&E St. 1 at 12.

The Company argued that the public advocates' recommendations relied on historically low interest rates instituted during the recent recession in an attempt to justify returns on common equity that are far below any allowed by this Commission in decades. Even in these difficult financial times, allowed ROEs have ranged between 9.75% and 10.99%. PPL M.B. at 87-88; PPL St. 12-R at 3-5. The Company averred that if either of these is adopted, Pennsylvania utilities will be placed at a disadvantage compared to other utilities in the country in terms of raising capital during what it terms to be a critical infrastructure replacement phase, PPL St. 12-R at 3-5, as well as at risk for another downgrade in its credit rating.[9] Of course, accompanying this would be higher debt costs and potential limits to access to capital in difficult markets. PPL M.B. at 87-88.

2. Capital Structure

Capital structure involves a determination of the appropriate proportions of debt and equity used to finance the rate base. This is crucial to developing the weighted cost of capital, which, in turn, determines the overall rate of return in the revenue requirement equation.

[9] Note that in presenting its 2004 rate case, PPL had an A minus rating, which it sought to retain at that time. *See,* Docket No. R-00049255, Recommended Decision of Administrative Law Judge Allison K. Turner, at 94.

a. Positions of the Parties

The Capital Structure recommendations of the Parties in this proceeding are summarized in the following table:

Capital Type	PPL (1)	I&E (2)	OCA (3)
	(%)	(%)	(%)
Debt	49.22	54.89	52.84
Common Equity	50.78	45.11	47.16
Total	100.00	100.00	100.00

(1) PPL M.B. at 91 fn. 16
(2) I&E St. 1 at 12
(3) OCA St. 2 at 25

As noted above, PPL proposed the use of its actual capital structure of 49.22% long-term debt and 50.78% common equity. According to the Company, the legal standard in Pennsylvania for deciding whether to use a hypothetical capital structure in setting rates is that if a utility's actual capital structure is within the range of a similarly situated barometer group of companies, rates are set based on the utility's actual capital structure. PPL stated that only if the capital structure is atypical, outside of the range of the barometer group, should a hypothetical capital structure be used to set rates for a utility. PPL R.B. at 41 (citing *Pa. PUC v. City of Lancaster – Water,* 1999 Pa. PUC Lexis 37 at *17; *Pa. PUC v. City of Bethlehem,* 84 Pa. P.U.C. 275, 304 (1995); *Carnegie Natural Gas Co. v. Pa. PUC,* 433 A.2d 938, 940 (Pa. Cmwlth. 1981) (where a utility's actual capital structure is too heavily weighted on either the debt or equity side, the Commission must make adjustments)).

Both I&E and the OCA sought to utilize a hypothetical capital structure in this proceeding. I&E stated that a capital structure should be representative of the industry norm and be an efficient use of capital. According to I&E, the use of a capital structure that is significantly outside the range of the industry's capital structure may result in an overstated overall rate of return. I&E advocated for the use of a hypothetical capital structure based upon an industry average for ratemaking purposes if the use of the utility's actual capital structure has the potential to overstate the overall cost of capital. I&E M.B. at 82.

The OCA submitted that the Commission should adopt a hypothetical capital structure for PPL as the Company's proposed capital structure is unnecessary to attract capital and would create an unreasonable cost burden for ratepayers. The OCA averred that its proposed capital structure of 47.16% equity and 52.84% debt is reasonable, consistent with how PPL has been capitalized over the last few years prior to this current rate filing, and similar to the manner in which the electric industry is capitalized. The OCA noted that of particular concern in this case is the percentage of common equity in the capital structure, since common equity commands a higher return than debt financing. OCA M.B. at 32-42

The I&E and the OCA recommendations to utilize a hypothetical capital structure are based upon use of a barometer group of companies with characteristics similar to PPL. The three Parties' barometer groups all contain comparison companies which are higher and lower than PPL's capital structure in this case.Error! Bookmark not defined. A barometer (or proxy) group is a group of companies that act as a benchmark for determining the utility's rate of return. I&E M.B. at 79. I&E noted that a barometer group is necessary because PPL is a private wholly owned subsidiary of PPL Corp. and is not publicly traded. According to I&E, using data from a group of companies is more reliable than data from a single company in that it smooths short-term anomalies and the use of a barometer group satisfies the long-established principle of utility regulation that seeks to provide the utility the opportunity to earn a return equal to that of similar companies with corresponding risks. I&E M.B. at 79 – 80.

PPL selected two barometer groups, an Electric Distribution Group (EDG) and an Integrated Electric Group (IEG). PPL's EDG group was based upon the following criteria:

1. Their stock is traded on the New York Stock Exchange;
2. They are listed in the Electric Utility (East) section of *The Value Line Investment Survey*;
3. They are not currently the target of a publicly-announced merger or acquisition; and
4. They do not have a significant amount of electric generation.

PPL's criteria for its IEG are identical except for criterion four, which requires that at least 75% of the companies' identifiable assets are subject to public regulation. PPL St. 11 at 4-5.

I&E used a barometer group comprised of Consolidated Edison, Dominion Resources, Nextera Energy, TECO Energy, PEPCO Holdings, and UIL Holdings. I&E St. 1 at 9-11. These were chosen by I&E based on the following criteria:

1. 50% or more of the company's revenue were generated from the electric distribution industry;
2. The company's stock was publicly traded;
3. Investment information for the company was available from more than one source;
4. The company was not currently involved/targeted in an announced merger or acquisition; and

5. The company had six consecutive years of historic earnings data.

I&E M.B. at 80.

The equity ratios for I&E's barometer group for 2011 range from 39.34% equity to 52.47% equity. I&E Exh. 1, Sch. 1 at 2. I&E then averaged the companies in its barometer group and developed a hypothetical capital structure based upon the average of 54.89% long-term debt and 45.11% equity for the FTY, or 55% debt/45% equity. I&E M.B. at 82.

The OCA used sixteen companies that had at least 70% of revenues from electric operations, did not have a pending merger, did not have a recent dividend cut, had stable book values and a senior bond rating between "A" and "BBB-". The OCA used "wires" companies as well as those with generation, and all were listed in *Value Line*. OCA St. 2 at 29-30. OCA M.B. at 52.

I&E argued that PPL's selected EDG and IEG barometer groups are flawed. According to I&E, Northeast Utilities must be excluded from PPL's EDG and Duke must be excluded from its IEG because their inclusion violates the Company's own presumably objective criteria number three in that Northeast is the subject of an announced merger with NSTAR and Duke is the subject of an announced merger with Progress Energy. I&E M.B. at 81. Also, I&E maintained that TECO Energy and Dominion Resources should be excluded from the Company's IEG and, instead, included in its EDG, because they derive more than 50% of their revenues from their regulated electric distribution sector. I&E further contended that the Company's IEG group should be disregarded in its entirety, because the group is too dissimilar in terms of business lines to be comparable to PPL in this proceeding. Specifically, I&E stated that PPL does not have regulated generation or gas distribution, properties common to SCANA Corp.

and Southern Co. included in the IEG, and neither company's revenues are derived more than 50% from electric distribution only. I&E St. 1 at 11-12. I&E M.B. at 80-82.

I&E asserted that PPL's claimed capital structure, if left unadjusted, overstated its capital needs by $15 million. I&E M.B. at 83. According to the OCA, the Company's equity-rich common equity ratio would cost its ratepayers an additional $10.6 million annually compared to the more economically efficient capital structure it has employed in recent years. OCA M.B. at 41.

b. ALJ's Recommendation

The ALJ concluded that the appropriate capital structure is the Company's actual capital structure of 49.22% long-term debt and 50.78% common equity. R.D. at 60.

c. Exceptions

In its Exceptions, the OCA states that PPL's proposed capital structure is unnecessarily burdensome to ratepayers, contains more common equity capital than the electric industry on average and is inconsistent with how PPL has been capitalized over the last several years prior to this rate case being filed. The OCA avers that its proposed capital structure of 47.16% equity/52.4% debt is reasonable, consistent with how PPL has been capitalized over the last few years and similar to the manner in which the electric utility industry is capitalized. The OCA notes that PPL's proposed capital structure is not really an "actual" capital structure, but rather a projection based on 2012 year-end data. OCA Exc. at 12-13.

Next, the OCA avers that the ALJ erred by finding that PPL's capital structure is not atypical, as the Company's proposed capital structure contains significantly more equity than comparable utilities. According to the OCA, the average common equity ratio for publicly-traded electric and combination gas and electric utilities is 45.9% as reported by AUS Utility Reports in its May 2012 publication. Also, the OCA submits that the average common equity ratio of PPL's IEG sample group, and the S&P Public Utilities was 44.4% and 45% in 2010, respectively. The OCA opines that these ratios are far below the 50.78% common equity ratio requested by PPL. According to the OCA, the Company's own barometer group shows that a 45% common equity ratio is common in the industry for publicly traded companies. OCA Exc. at 13-14.

The OCA submits that Pennsylvania courts have upheld the use of a hypothetical capital structure where the utility's management adopts an actual capital structure that imposes an unfair cost burden on ratepayers. The OCA refers to *T.W. Phillips Gas and Oil Co. v. Pa. PUC,* 474 A.2d 355, 362 (Pa. Cmwlth.1984) and *Carnegie Natural Gas Co. v. Pa. PUC*, 433 A.2d 938 (Pa. Cmwlth. 1981) as support for its assertion. OCA Exc. at 14.

Next, the OCA reiterates that PPL's average common equity ratio from 2006 through 2010 was 43.7% of permanent capital per PPL's Exhibit PRM 1, Schedule 2. According to the OCA, PPL's requested ratemaking capital structure contains considerably more common equity than that with which it has been successfully capitalized historically. The OCA states that PPL plans to reduce its reliance on preferred stock and increase its reliance on more expensive common equity by means of a $150 million capital contribution to PPL by its parent company, which is a management decision at PPL Corporation that changes the regulated capital structure of PPL. The OCA avers that this new test year capitalization will cost the Company's ratepayers approximately $10.6 million more every year than the capital structure the Company has relied on for many years. The OCA submits that ratepayers should not bear this unnecessary and unfair burden and that the ALJ's recommendation should be rejected. OCA Exc. at 14-15.

I&E also excepts to the ALJ's recommendation on capital structure, stating that the ALJ erred in not applying a more cost-efficient capital structure for PPL, using I&E's calculated industry average, particularly because PPL's more expensive equity ratio is assigned by its affiliate. I&E avers that a hypothetical capital structure based upon an industry average should be used for ratemaking purposes if use of the utility's actual capital structure has the potential to overstate the overall cost of capital. I&E recommends a hypothetical capital structure based upon its industry average of 54.89% long-term debt and 45.11% equity for the FTY. According to I&E, PPL's proposed capital structure is neither representative of the industry norm nor an efficient use of capital. I&E Exc. at 15-16.

I&E submits that while the differences between PPL's and I&E's proposed capital structures are nuanced, PPL's actual capital structure includes sufficiently more expensive equity than less expensive debt, such that I&E's proposed adjustment is appropriate. According to I&E, imposing the industry average capital structure upon PPL saves ratepayers an annual $15 million while still providing the Company competitive and effective means to finance its capital needs. This is particularly true, alleges I&E, given today's economic environment where debt rates have been and remain at all-time lows, and where PPL's capitalization is controlled by its affiliate, which is financially accountable to PPL's corporate parent and not PPL's ratepayers. I&E offers that if the corporate family is unwilling to take advantage of historically low interest rates to benefit its affiliated rate-regulated entity's ratepayers, then it is incumbent upon this Commission to do so. I&E Exc. at 17.

Next, I&E avers that contrary to PPL's characterization, the legal standard for employment of a hypothetical capital structure is not that the actual capital structure is "atypical." Rather, I&E maintains that use of a capital structure that is representative of the industry average presents a better option for PPL's efficient capitalization than the capital structure assigned to PPL by its corporate family. According to I&E, use of a barometer group average is more reliable than comparing data from individual companies as individual company data may be subject to short-term anomalies that distort its return on equity. I&E notes that its industry average, as well as the common equity ratio averages from PPL's own barometer groups (44.8% for EDG, 45.1% for IEG and 45.3% for the S&P Public Utilities) more closely support I&E's recommended capital structure of 45% equity and 55% debt. I&E Exc. at 18.

In conclusion, I&E submits that while it agrees that PPL's actual capital structure does not deviate substantially from the industry range, the applicable legal standard is not that the capital structure must be "atypical" before a hypothetical structure should be considered. I&E notes that Commission decisions have specifically avoided setting numeric standards to define efficient capital structures, instead using standards such as "in proper proportions," "on balance," and not "too heavily weighted" one way or another. I&E opines that a $15 million ratepayer expense based solely upon a capital structure chosen by the same PPL affiliates that benefit from the profitability of the rate regulated entity is unfair and unreasonable to ratepayers because it can be moderated without financial harm to PPL through a minor adjustment to the rate-regulated entity's capital structure. Therefore, I&E requests that its capital structure be adopted to impartially achieve a fair balance of ratepayer and shareholder interests. I&E Exc. at 21-22.

In reply, PPL states that the ALJ's recommendation should be accepted as its actual capital structure is not atypical and, pursuant to precedent, provides no basis to employ a hypothetical capital structure. Also, PPL states that it requires an equity ratio near the high end of the historic range employed by the barometer group companies to support its expanded infrastructure replacement program and its credit rating. According to PPL, the OCA and I&E misstate the circumstances that authorize the use of a hypothetical capital structure. PPL avers that both Parties rely on statements in cases where the utility's equity ratio was outside the range of the equity ratios of barometer group companies to contend that a hypothetical capital structure should be employed in this proceeding where the actual equity ratio is clearly within the historic range of equity ratios employed by barometer group companies. PPL opines that while the cases cited identify the Commission's power to employ a hypothetical capital structure where the actual capital structure is extreme and atypical, they do not address how to determine when the actual capital structure is atypical. PPL R. Exc. at 3-4.

Next, PPL avers that its equity ratio is not atypical and provides no basis for use of a hypothetical capital structure and that its equity ratio is necessary to support its ability to attract capital and maintain its credit rating. PPL maintains that these are important considerations as it continues to ramp up its infrastructure replacement program. PPL avers that the OCA and I&E are ignoring the fact that PPL's unsecured bond was downgraded from Baa1 to Baa2 by Moody's Investors Service in April of 2010 due to Moody's opinion that PPL's cash flow metrics will decline from their recent levels due, in part, to the increased expenditures for capital investments needed to maintain PPL's aging delivery systems. According to PPL, the modest increase in the equity ratio was designed to avoid any further downgrade of PPL's rating to Baa3 and is consistent with projections of increasing equity ratios for other electric utilities as they expand their infrastructure replacement programs. PPL R. Exc. at 4-5.

Finally, PPL avers that the OCA's and I&E's claimed savings calculations are illusory because they incorrectly assume that PPL can undertake a dramatically expanded infrastructure program without strengthening its equity ratio. PPL states that it should not be placed at a disadvantage in raising capital and be placed at risk of a further downgrade by adopting a hypothetical equity ratio. Also, PPL avers that the OCA's and I&E's calculations are erroneous because they ignore the fact that a substantial part of the increase in PPL's equity ratio results from refinancing preference stock, which does not receive a tax deduction on dividends, with 50% equity and 50% tax deductible debt at a small net savings to ratepayers. As a result, PPL explains that the Parties alleged savings from a lower equity ratio are significantly overstated because they incorrectly assume that the increased equity to refinance preference stock increases costs to ratepayers. PPL R. Exc. at 6.

d. Disposition

Upon our consideration of the evidence of record, the Recommended Decision and the Exceptions and Reply Exceptions filed by the Parties, we are persuaded by the position of PPL to adopt the Company's actual capital structure and affirm the recommendation of the ALJ. It is important to note that the actual capital structure represents the Company's decision, in which it has full discretion, on how to capitalize its rate base. This actual capitalization forms the basis upon which PPL attracts capital. PPL's debt cost rate of 5.50%, which all Parties have accepted for ratemaking purposes, fully reflects the capitalization determined by the Company to be appropriate. Absent a finding by the Commission that a utility's actual capital structure is atypical or too heavily weighted on either the debt or equity side, we would not normally exercise our discretion with regard to implementing a hypothetical capital structure. *See, Pa. PUC v. City of Lancaster –Water*, 1999 Pa. PUC Lexis 37 at *17; *Carnegie Natural Gas Co. v. Pa. PUC,* 433 A.2d 938, 940 (Pa. Cmwlth. 1981). With regard to these factors, we are persuaded by the arguments of PPL that its actual capital structure is not atypical, is within a range of reasonableness, and, pursuant to precedent, provides no basis to employ a hypothetical capital structure. Also, we are further swayed by PPL's assertion that it requires an equity ratio near the high end of the historic range employed by the barometer group companies to support its expanded infrastructure replacement program and its credit rating.

Accordingly, based upon the foregoing discussion, we shall deny the Exceptions of I&E and the OCA, and adopt the recommendation of the ALJ to utilize PPL's actual capital structure of 49.22% long-term debt and 50.78% common equity.

3. Cost of Debt

PPL proposed to use its expected cost of long-term debt and amortization of loss on reacquired debt for the FTY of 5.50%. PPL M.B. at 91. Both I&E and the OCA agree with PPL that 5.50% is the appropriate cost of long-term debt for purposes of this proceeding.[10] I&E M.B. at 83; OCA M.B. at 46. This cost of debt was unopposed by any Party. R.D. at 60. No Exceptions were filed on this issue. Finding the PPL proposed cost of debt to be reasonable and appropriate, we adopt it without further comment.

4. Cost of Equity

a. Overview

Although there are various models used to estimate the cost of equity, the Discounted Cash Flow (DCF) method applied to a barometer group of similar utilities, has historically been the primary determinant utilized by the Commission. *Pa. PUC v. City of Lancaster – Bureau of Water*, Docket No. R-2010-2179103, at 56 (Order entered July 14, 2011); *Pa. PUC v. PPL Electric Utilities Corp*., Docket No. R-00049255, at 59 (Order entered December 22, 2004). The DCF model assumes that the market price of a stock is the present value of the future benefits of holding that stock. These benefits are the future cash flows of holding the stock, *i.e.*, the dividends paid and the proceeds from the ultimate sale of the stock. Because dollars received in the future are worth less than

[10] As noted above, PPL adjusted its long-term debt cost to reflect the results of the Company's actual issuance of $250 million of long–term debt, which reduced its weighted average long-term debt cost to 5.50%. PPL M.B. at 91.

dollars received today, the cash flow must be "discounted" back to the present value at the investor's rate of return.

b. Summary

In the instant proceeding, only PPL, I&E and the OCA presented a position on a reasonable rate of return on equity (ROE). The Parties' positions were generally developed through comparison groups' market data, costing models, reflection or rejection of risk and leverage adjustments and a management performance adjustment, as will be further addressed, *infra*. The following table summarizes the cost of common equity claims made and the methodologies used by the Parties in this proceeding:

	DCF (%)	RP (%)	CAPM (%)	CE (%)	Risk (%)	Leverage (%)	MEA (%)	ROE (%)
PPL-EDG	9.67	10.75	10.58	11.60	1.20	0.7	0.12	11.13
PPL-IEG	9.69	10.75	11.28	11.60	1.20	1.18	0.12	11.43
OCA	8.97	7.3	-----	-----	0	0	0	9.00
I&E	8.38	-----	8.68	-----	0	0	0	8.38
ALJ	9.68	-----			0	0	0.06	9.74

PPL proposed a common equity cost rate of 11.25% based on the results of the DCF, Risk Premium (RP), Capital Asset Pricing Model (CAPM) and Comparable Earnings (CE) methodologies. PPL included a risk adjustment of 120 basis points, a leverage adjustment of 70 basis points, and a management performance adjustment of 12 basis points to arrive at its total request. PPL stated that the use of more than one method provides a superior foundation to arrive at the cost of equity. According to PPL, at any point in time, reliance on a single method can provide an incomplete measure of the cost of equity. PPL St. 11 at 5-6.

Both the OCA and I&E argued that an 11.25% return on equity is excessive. The OCA stated that it would result in a shareholder windfall at the expense of ratepayers and would result in rates that are unjust and unreasonable. The OCA stated that "the current and near-term future economic outlook is one that includes a low cost of capital." OCA St. 2 at 11-19. The OCA proposed a common equity cost rate of 9.00%, based primarily on the results of the DCF analysis without consideration of any of the additional adjustments proposed by the Company. The OCA utilized a CAPM, a Modified Earnings-Price Ratio (MEPR) and a Market-to-Book Ratio analyses as a check on the reasonableness of the DCF results. The OCA also cited numerous other jurisdictions which have awarded less than 10% returns on equity. OCA M.B. at 47-52 (citing *e.g.*, *In re PEPCO*, Order No. 85028 (MD PSC, July 20, 2012) (authorizing a 9.31% ROE)).

I&E recommended a cost of common equity of 8.38% based on the DCF methodology, with consideration of CAPM as a check, with no additional adjustments. I&E's analysis used a spot dividend yield and a 52-week dividend yield, and a combination of earnings growth forecasts and a log-linear regression analysis growth rate. Using the standard DCF model formula,[11] I&E recommended a dividend yield of 4.89% and a recommended growth rate of 3.49%. I&E M.B. at 84-86.

---

[11] I&E St. 1 at 24.

c. Cost Rate Models

i. Positions of the Parties

PPL performed a RP analysis to determine the cost of equity, based upon the basic financial tenet that an equity investor in a company has greater risk than a bond holder in a company. PPL explained this is because all interest on bonds is paid before any return is received by the equity investor, and, upon bankruptcy or dissolving a company, the bond holder receives his capital before any capital is provided to the equity investors. PPL M.B. at 109-110; PPL St. 11 at 44; Appendix G at G-2.

PPL claimed that the RP method has common sense appeal to investors, who would expect to earn equity returns in excess of bond returns, as has been the case for any extended period in the capital markets. Accordingly, the Company explained the RP method as determining the cost of equity by summing the expected public utility bond yield and the return of equities over bond returns (the "equity premium") over a historic period, as adjusted to reflect lower risk of utilities compared to the common equity of all corporations. PPL St. 11 at 49-50; PPL M.B. at 110.

The Company determined the RP cost of equity to be 10.75% as follows:

Interest Rate		Risk Premium		Cost Rate
5.25%	+	5.50%	=	10.75%

Id.

PPL also performed a CAPM analysis to estimate the cost of equity for the EDG and IEG and determined the risk free rate to be 3.75% based on current and near term project yields on long term treasury bonds. PPL St. 11 at 53-54. According to PPL, the CAPM analysis determines a "risk-free" interest rate based on U.S. Treasury obligations and an equity risk premium that is proportional to the systematic (*i.e.,* beta) risk of a stock, which are combined to produce cost rate of equity. PPL St. 11 at 50-52.

PPL determined the market or equity premium to be 8.76% based upon an average of historic and projected market premiums. PPL St. 11 at 54; Appendix H at H-4 - H-6. PPL stated that betas are applied to the market premiums to adjust for electric company risks relative to the total market, and the betas are adjusted for the same reasons as the leverage adjustment to the DCF. PPL St. 11 at 52-53. Finally, the Company added a size adjustment to reflect greater risk for smaller firms relative to the market. PPL St. 11 at 54-55. The result of the PPL CAPM analysis was 11.78% for the EDG and 12.48% for the IEG. According to PPL, the results of the CAPM analysis indicate the upper range of the cost of equity analysis using the theoretical models typically employed in utility rate cases. PPL M.B. at 113.

PPL further performed a CE analysis. PPL noted that because regulation is a substitute for competitively determined prices, returns realized by non-regulated firms with similar risks can be used as a guide to determine a fair rate of return. PPL St. 11 at 56. Based on the PPL analysis, the comparable earnings group yielded an historical return of 10.9% and a forecasted return of 12.3%, which resulted in an average return of 11.6%. PPL M.B. at 113-114.

I&E stated that while it was not opposed to using the CAPM results as a comparison to the results of the DCF calculation, it is inappropriate to give the CAPM, RP and CE models comparable weight. I&E St. 1 at 38. I&E recommended against using the RP method and averred that it cannot be used because it relies on historic risk premiums achieved over bond yields which may not be applicable to the future. I&E St. 1 at 19.

Both the OCA and I&E used a CAPM as a check of reasonableness for their DCF calculations. However, both also believe there are shortcomings to this model, express concerns regarding its use and note their preference for using the DCF model to determine the cost of equity capital. I&E M.B. at 85; OCA St. 2 at 39.

I&E also performed an analysis of a return on equity using the CAPM methodology but gave no specific weight to its CAPM results because of its concerns that unlike the DCF, which measures the cost of equity directly by measuring the discounted present value of future cash flows, the CAPM measures the cost of equity indirectly and can be manipulated by the time period used. However, having presented two analyses – historic and forecasted – both of which are comprehensive in the time periods covered, I&E submitted that for purposes of providing another point of comparison, the 8.68% simple average of those two analyses confirmed the reasonableness of the I&E 8.38% return under its DCF calculation. I&E St. 1 at 31-36; I&E M.B. at 88-89.

In its CAPM analysis, OCA chose a risk free rate based on the long-term trend for Treasury Bonds, which it determined to be 4% for a forward looking CAPM analysis. Based on historical Morningstar data which shows an 11.8% return on stocks and a 5.8% return on long-term Treasury bonds since 1926, the OCA determined a risk premium of 6%; yielding an overall expected stock market return of 10% (4% + 6%). The OCA determined a beta of 0.69 based on *Value Line* beta coefficients for its electric group. Based on this analysis, the OCA's CAPM analysis yielded a cost of equity of 8.14% (4 %+(0.69*6%)). OCA St. 2 at 41-44.

I&E did not perform a CE analysis. I&E stated that the CE methodology is subjective in terms of the selection of comparable companies, has generally been rejected by the Commission and, in PPL's particular analysis, compares projected returns of companies of dissimilar business and financial risks.[12] I&E M.B. at 92.

ii. ALJ's Recommendation

Based on the I&E position, the ALJ recommended that reliance on the RP method be denied. The ALJ concluded that the Commission's preferred method of determining a utility's ROE is the DCF model. The ALJ recommended utilization of the I&E DCF analysis. R.D. at 78, 93.

d. Dividend yields

i. Positions of the Parties

PPL derived the dividend yield by calculating the six month average dividend yields for each group and adjusting those yields for expected growth in the following year to produce the 4.67% for the Electric Delivery Group and 4.69% for the Integrated Electric Group. PPL St. 11 at 26; PPL M.B. at 104.

I&E stated that a representative yield must be calculated over a time frame sufficient to avoid short-term anomalies and stale data. The I&E's dividend yield calculation placed equal emphasis on the most recent spot (4.78%) and 52-week average (5%) dividend yields resulting in an average dividend yield of 4.89%. I&E St. 1 at 40-41; I&E M.B. at 86.

The OCA employed a 4.44% DCF adjusted yield, based upon the average dividend yield of its proxy group of similar companies. OCA St. 2 at 38; OCA M.B. at 55.

---

[12] I&E St. 1 at 19-23, 38-39.

ii. ALJ's Recommendation

For the reasons set forth by I&E, the ALJ recommended the adoption of the I&E proxy group and methodology for determining a 4.89% dividend yield. R.D. at 66.

e. Growth Rates

i. Positions of the Parties

PPL reviewed various methods of calculating investor expected growth rates and concluded that analysts' projections of growth rates are the best indicator of expected growth. PPL St. 11 at 34. PPL arrived at a range of growth rates from 4.50% to 5.08% for the EDG and from 4.59% to 6.00% for the IEG. PPL chose a growth rate of 5.00% based upon an average EDG growth rate of 4.87% and an average IEG growth rate of 5.14%. PPL M.B. at 105.

I&E used both earnings growth forecasts and a log-linear regression analysis data to calculate its expected growth rate. The I&E earnings forecasts were developed from projected growth rates using five-year estimates from established forecasting entities for the selected barometer group of companies, yielding an average five-year growth forecast of 4.79%. I&E St. 1 at 25-26.

I&E averred that investor forecasts may be biased and/or distorted by misestimates and, therefore, used a log-linear regression analysis to determine a more appropriate long term growth rate. I&E's log-linear regression analysis used historic earnings per share (EPS) from *Value Line* for the years 2006-2011, and the financial analysts forecasted growth rate to project EPS values for the FTY (2012) through 2016. The result of this log-linear regression analysis provided an average growth rate of 3.49%. I&E St. 1 at 25-30; I&E M.B. at 85-86.

ii. ALJ's Recommendation

The ALJ recommended using the 4.79% growth rate of I&E without the log-linear analysis. R.D. at 68.

Based upon the ALJ's recommendation with regard to her dividend yield recommendation of 4.89% and her 4.79% recommendation for PPL's growth rate, the ALJ recommended utilization of a DCF based 9.68% cost of equity, prior to the adoption of any of PPL's proposed adjustments.

iii. Exceptions

PPL excepts to the ALJ's conclusion with regard to its cost rate for common equity, stating that the ALJ's recommendation is far too low and should be increased to at least 10.5%. PPL avers that the principal error in the ALJ's analysis contained in the Recommended Decision is its sole reliance on an unadjusted DCF cost rate without any check on its validity. PPL submits that the ALJ simply rejects the results of other cost rate models based on alleged flaws in the models without recognition of the flaws of the DCF model. PPL Exc. at 6-7.

With regard to the ALJ's rejection of the RP method, PPL states that the RP method has particular applicability in this case because it reflects the prospective A-rated public utility bond yield under current market conditions. Therefore, PPL alleges, it reflects interest rates to be experienced by public utilities during the period rates will be in effect. According to PPL, using an A-rated bond yield produces an equity cost rate below PPL's cost rate because PPL is rated Baa2, indicating a higher cost of debt and equity. PPL notes that the OCA witness admitted that risk premiums tend to increase during periods of lower interest rates. PPL Exc. at 8; Tr. at 329-330. Accordingly, PPL submits that it is likely that the lower interest rates currently being experienced indicate that the average historic premium understates the premium expected by investors for the future. This, PPL asserts, makes the RP analysis in this case conservatively low under current market conditions. PPL opines that the 10.75% RP provides a clear demonstration of the inadequacy of the unadjusted DCF analysis. PPL Exc. at 7-8.

With regard to the ALJ's rejection of the CAPM analysis as a check on the ROE recommendation, PPL submits that the ALJ simply accepted the OCA's and I&E's contention that there are "shortcomings" in the model. PPL avers that its CAPM analysis resulted in a cost rate of 10.58%, after removal of the 120 basis point size adjustment which the ALJ's rejects. PPL maintains that the ALJ did not provide any basis for rejecting the revised CAPM analysis excluding the size adjustment. PPL notes that the ALJ herself noted that the Commission has concluded that it is necessary to use other methods as a check on the results of the DCF, citing the Commission decision in PPL's 2004 rate case. PPL proffers that based on that decision, the ALJ's sole reliance on a DCF analysis with no leverage adjustment should not be adopted. According to PPL, the ALJ failed to follow the Commission precedent by either adding the leverage adjustment to the unadjusted DCF result or relying on other methods, such as the RP. PPL Exc. at 9-10.

PPL further excepts to the ALJ's apparent reliance on the Maryland *In re PEPCO* decision, *supra*, to justify an ROE less than 10%. PPL avers that neither the ALJ nor the OCA cites a further quote from the *In re PEPCO* decision provided in the Company's Reply Brief, which explained that the ROE that was approved for PEPCO reflected poor service quality and the effects of a revenue decoupling mechanism employed by PEPCO. PPL maintains that neither of those circumstances apply to PPL and, as such, the 9.31% ROE does not demonstrate the reasonableness of the ALJ's recommended allowance for PPL in this proceeding. PPL notes that the ROE should reflect prospective conditions, as relying too much on the past can risk under-estimating the cost of equity capital that PPL will face as it seeks to raise capital to fund its expanded infrastructure improvement program during the period that rates set in this proceeding will be in effect. PPL Exc. at 16-19.

In reply, the OCA avers that the ALJ was correct in primarily relying on the DCF results to arrive at a reasonable ROE for PPL. The OCA states that the ALJ spent considerable effort in her Recommended Decision reviewing and discussing the results of the Parties' various ROE estimating studies, other than the DCF, and that PPL's criticism of the ALJ for relying on an unadjusted DCF result without any check on its validity is unwarranted. According to the OCA, the ALJ correctly concluded that the Commission primarily relies on the DCF method to establish a reasonable ROE. The OCA points out that the ALJ provided an extensive discussion and review of the results of the RP analysis, the CAPM analysis, and PPL's CE study, which led the ALJ to conclude that they should not be relied upon in this proceeding. The OCA submits that the ALJ's conclusion to rely primarily on the DCF method to arrive at an ROE recommendation is consistent with well-established Commission precedent and should be accepted. OCA R.Exc. at 4-8.

In response to PPL's Exception with regard to the *PEPCO* decision referenced by the ALJ, the OCA states that PPL's attempt to differentiate the *PEPCO* decision from its situation is without merit. The OCA submits that the quoted portions of the *PEPCO* Order only serve to reinforce the fact that the ALJ's recommendation of a 9.68% ROE is adequate and reasonable. According to the OCA, PPL is similar to PEPCO as it owns no generation, has no competition for distribution service and serves a heavily residential customer base, so PPL's attempts to distance itself from PEPCO is without merit and should be rejected. OCA R.Exc. at 10-14.

In its Reply Exceptions, I&E asserts that the ALJ's 9.68% calculated ROE is supported by the record and should be adopted. I&E asserts that as this Commission recently confirmed, although it may review other results as a check, the Commission relies primarily on the DCF methodology. I&E R.Exc. at 18 (citing *Pa. PUC v. City of Lancaster – Bureau of Water*, Docket No. R-2010-2179103, at 56 (Order entered July 14, 2011)). Therefore, I&E avers that PPL's assertions are erroneous as the DCF has always been the primary standard. Notwithstanding this position, I&E posits that the reasonableness of the ALJ's recommendation was confirmed by I&E's two CAPM analyses, the historic and forecasted. According to I&E, its 8.68% simple average of its two CAPM studies, employing the same simple averaging PPL undertook of its four methodologies, confirmed the reasonableness of I&E's DCF return of 8.38%. I&E points out that since the ALJ rejected its log linear regression analysis, the ALJ's recommended 9.68% recommended ROE is substantially higher than the 8.68% check provided by its CAPM analysis. I&E R.Exc. at 17-19.

iv. Disposition

Upon our consideration of the record evidence, we agree with the finding of the ALJ that the Company's cost of equity in this proceeding should primarily be based upon the use of the DCF methodology. We also are persuaded by the arguments of PPL that it is important to temper the results of the unadjusted DCF results in comparison to the results from the other cost of equity methodologies as presented by the Parties in the context of this proceeding. Sole reliance on one methodology without checking the validity of the results of that methodology with other cost of equity analyses does not always lend itself to responsible ratemaking. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived equity return calculation. *See*, *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-00049255, at 67 (Order entered December 22, 2004). It is important to recognize that each of the Parties presenting a cost of equity position in this proceeding have done so. We also note that we historically have primarily relied upon the DCF methodology in arriving at previous determinations of the proper cost of equity and utilized the results of methods, such as the CAPM and RP methods, as a check upon the reasonableness of the

DCF derived equity return amount, tempered by informed judgment. As such, where evidence based on the CAPM and RP methods suggests that the DCF-only results may understate the utility's current cost of equity capital, we will give consideration to those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. Therefore, we are not in agreement with the ALJ that the proper ROE in this proceeding should be determined based strictly on the reliance of the unadjusted DCF calculations presented by the Parties.

In *Lower Paxton Township v. Pa. PUC,* 317 A.2d 917, 920-921 (Pa. Cmwlth. 1974), the Commonwealth Court recognized that the Commission may consider its judgment as well as other factors which affect the cost of capital, including the utility's financial structure, credit standing, dividends, risks, regulatory lag and any peculiar features of the utility involved. The Court stated that "the cost of capital is basically a matter of judgment governed by the evidence presented and the regulatory agency's expertise." *Id*. at 921. Here, we are guided by the legal analysis in *Lower Paxton.* In this case, we will rely upon the DCF methodology and informed judgment in arriving at our determination of the proper cost of common equity. In particular, we note that the evidence presented in this case based on the CAPM and RP methods produced a range of results that was consistently higher than the results produced by a DCF-only approach. This suggests that, while properly computed in the abstract, the DCF-only results understate the current cost of equity for PPL and that consideration should be given to the CAPM and RP evidence in determining the appropriate range of reasonableness. Furthermore, we note that the setting of the proper return on equity is even more critical in this proceeding as our Pennsylvania jurisdictional utilities implement plans to accelerate the greatly needed replacement of aging infrastructure. Attracting capital to Pennsylvania at reasonable rates to accomplish this infrastructure replacement has never been more important to PPL, its customers and the Commonwealth of Pennsylvania.

Based upon our analysis and review of the record evidence, we find that a range of reasonableness for the cost of equity in this proceeding is from 9.0% to 11.25%. We conclude that within that range, considering PPL's need to fund $1.6 billion of planned distribution improvements between 2012 and 2016, a cost of common equity of 10.28% is reasonable and appropriate to incorporate into our return determinations under the circumstances of this proceeding. We note that this return on equity is exclusive of any of the PPL-requested adjustments to be discussed, *infra.* We note, further, that (1) the DCF-derived cost of equity ranged from 8.38% (I&E) to 9.69% (PPL); (2) the range determined from the RP methodology was 7.3% (OCA) to 10.75% (PPL); and (3) the range of the CAPM calculations was 8.14% (OCA) to 11.28% (PPL). Based upon our consideration and analysis of this evidence, as explained herein, we are of the opinion that an equity return of 10.28% is reasonable and appropriate for PPL.

Accordingly, the Exceptions of PPL are granted, in part, to the extent consistent with the foregoing discussion.

f. Leverage Adjustment

i. Positions of the Parties

PPL promoted a leverage adjustment in this proceeding, which it explained was designed to adjust the DCF cost rate for the different percentage level of debt in the capital structure when capital structure is calculated at the market prices of equity and debt securities as opposed to book value. PPL M.B. at 105.

PPL proposed a 70 basis point leverage adjustment to its EDG and a 118 basis point leverage adjustment to its IEG. PPL theorized that if regulators use the results of the DCF to compute the weighted average cost of capital based on a book value capital structure used for ratemaking purposes, the utility will not, by definition, recover its risk-adjusted capital cost. PPL believed this is because market valuations of equity are based on market value capital structures, which in general have more equity, less debt and, therefore, less risk than the capitalization measured at its book value. PPL St. 11 at 35.

The Company pointed out that the Commission has accepted the leverage adjustment in a number of cases, including PPL's last fully litigated rate case in 2004. PPL M.B. at 107 (citing *Pa. PUC v. Pa. American Water Co.*, Docket No. R-0001639 (Order entered January 10, 2012) (60 basis point adjustment); *Pa. PUC v. Philadelphia Suburban Water Company,* Docket No. R-00016750 (Order entered August 1, 2002) (80 basis points); *Pa. PUC v. Pa. American Water Co.*, Docket No. R-00038304 (Order entered November 8, 2004) (60 basis points affirmed); *Popowsky v. Pa. PUC*, 868 A.2d 606 (Pa. Cmwlth. 2004); *Pa. PUC v. Aqua Pa. Inc.*, Docket No. R-00038805 (Order entered August 5, 2004) (60 basis point adjustment); *Pa. PUC v. PPL Electric Utilities Corp.,* Docket No. R-00049255 (Order entered December 22, 2004) (45 basis point adjustment); *Pa. PUC v. PPL Gas Utilities Corp.,* Docket No. R-00061398 (Order entered February 8, 2007) (70 basis points)).

According to PPL, use of the DCF alone, and without consideration of the leverage adjustment, significantly understates the cost of equity. PPL opined that when investors' expectations of future earnings are pessimistic due to factors including future regulatory allowances, there is the potential for the DCF to be circular and not market based. PPL St. 11 at 24; PPL M.B. at 108.

I&E argued that rating agencies assess financial risk based upon the Company's booked debt obligations and the ability of its cash flow to cover the interest payments on those obligations by using financial statements, particularly income statements, for their analyses, not market capitalization.

I&E pointed out that, while the Commission has granted this adjustment on occasion, it has also rejected it:

> In a Blue Mountain Water Company case on remand from Commonwealth Court to clarify findings concerning fair rate of return, the Commission identified seven principles that were applied to analyze the company's required and lawful rate of return. The Commission's third identified principle stated that "[m]arket price-book value ratios are not a goal of regulation but a result of regulation, general economic factors and individual company's characteristics of management, operations and perceived future. *In general, we view a market-book ratio in the area of one-to-one as appropriate for regulated industry*."[13]
>
> In a 2008 case involving Aqua Pennsylvania, Inc., the Commission rejected the ALJ's recommendation for a leverage adjustment stating, "the fact that we have granted leverage adjustments in the past does not mean that such adjustments are indicated in all cases."[14] In a 2007 Metropolitan Edison Company case, the Commission rejected the Company's financial risk increment related to the leverage difference between market capital structures and book value capital structures.[15] Most recently in a City of Lancaster case, the Commission agreed with Ms. Sears' recommendation to reject the leverage adjustment, stating "any adjustment to the results of the market based DCF as we have previously adopted are unnecessary and will harm ratepayers. Consistent with our determination in *Aqua 2008* there is no need to add a leverage adjustment."[16]

I&E M.B. at 73-74.

---

[13] *Pa. PUC v. Blue Mountain Consolidated Water Co*., 1982 WL 213115, at 1 (emphasis added).

[14] *Pa. PUC v. Aqua Pennsylvania, Inc.*, Docket No. R-00072711, at 38 (Order entered July 31, 2008).

[15] *Pa. PUC v. Metropolitan Edison Co.*, Docket No. R-00061366, at 34 (Order entered January 11, 2007).

[16] *Pa. PUC v. City of Lancaster – Bureau of Water*, Docket No. R-2010-2179103, at 79 (Order entered July 14, 2011).

I&E determined that there are six cases in which the Commission accepted the leverage adjustment, most recently in 2007. According to I&E, the adjustment has been proposed in sixty-eight cases over a twenty-three year period, yielding six successful results. Finally, I&E charged that PPL's formulae for the adjustment are flawed as it used formulae which do not appear in the research cited to support it. I&E M.B. at 100.

The OCA recommended against the Company's leverage adjustment because there was no evidence to support a risk difference between a market-based capital structure and a book value capital structure. Rather, according to the OCA, the claim that the DCF results should be increased by 70-118 basis points due to PPL's leverage adjustment is "not sound ratemaking." OCA M.B. at 60. The OCA submitted that no ROE-enhancing adder is needed or appropriate for PPL based on the facts of this matter. As the OCA witness testified:

> While there are certainly many aspects of rate of return analysis that are subject to judgment and, thus, debate regarding the proper application of a particular technique, Mr. Moul's use of an imaginary risk difference between a market-based capital structure and a book value capital structure is not one of them. There is no evidence available in the literature of financial economics to support any risk difference between market-value and book-value capital structures. Miller and Modigliani (supposedly the source of Mr. Moul's "leverage" adjustment) do *not* compare market-value and book value capital structures.

OCA St. 2-SR at 4. (emphasis in original).

According to the OCA, PPL testified that when utility market prices exceed book values, a risk difference exists between market-value capital structures and book-value capital structures, and market-based cost of equity estimates should, therefore, be adjusted upwards to account for that risk difference. The OCA noted that this is the basis for PPL's "leverage adjustment." OCA St. 2 at 55-56. The OCA witness testified as to the flawed nature of this theory, in relevant part:

> There simply is no difference in financial risk when the market-value capital structure of a firm is different from the book-value capital structure. Financial risk is a function of the interest payments on the debt issued by the firm. That is, a firm's debt payments create financial risk and when the amount of debt used to finance plant investment increases relative to common equity the financial risk increases. Whether the capital structure is measured with market values or book values, the debt interest payments do not change and, therefore, financial risk does not change. As a result, market-value capital structures are useful as indicators of financial risk only when they are compared with other market-value capital structures (as Miller and Modigliani do in their treatise), and Mr. Moul's mixed-metaphor comparison of market-value and book-value capital structures has no economic meaning.

OCA St. 2 at 56.

> The Company is making an improper comparison between market value capital structures and book value capital structures in order to claim that a financial risk difference exists. When utility common equity market prices are above book value, the capital structure measured with market values will have a higher equity percentage and lower debt percentages than the capital structure measured with book value. That does not mean, as the Company claims, that those different capital structure measures signify any difference whatsoever in financial risk.

OCA St. 2 at 61.

The OCA acknowledged that, in some cases, the Commission made an adjustment to a DCF based cost of equity such as that proposed by PPL. However, the OCA claimed that, more recently, the Commission has not adopted PPL's leverage adjustment, as Mr. Hill testified:

> [I]t is important to note that this Commission has rejected "financial risk adders" in Docket No. R-00061366 (Metropolitan Edison (Met Ed), Pennsylvania Electric, Opinion and Order, January 11, 2007, p. 136). The "financial risk adders" in the Met Ed case were based on the leverage/risk difference between market-value capital structures and book value capital structures, just as Mr. Moul's are. In addition, in Docket No. R-00072711, Aqua Pennsylvania, Inc., July 17, 2008, at pages 35 through 39, this Commission specifically rejected Mr. Moul's leverage/risk analysis—the same leverage/financial risk adjustment Mr. Moul uses in his testimony in this proceeding.

OCA St. 2 at 57. The OCA argued that other state commissions have uniformly recognized this type of adjustment as unwarranted in their decisions. OCA M.B. at 62 (citing *West Virginia Public Service Comm'n v. West Virginia-American Water Works*, 2004 W. Va. PUC Lexis 6 at *18 (2004)). In addition to the West Virginia Public Service Commission, other Commissions have rejected similar market-to-book adjustments to the DCF model. The District of Columbia Public Service Commission rejected a company's arguments that an adjustment to the DCF was appropriate to meet investors' requirements. OCA M.B. at 62 (citing *In the Matter of the Application of Washington Gas Light Company, District of Columbia Division, for Authority to Increase Existing Rates and Charges for Gas Service,* 2003 D.C. PUC Lexis 220 at *72 (2003)).

In its surrebuttal testimony in this proceeding, the OCA summarized the reasons this Commission should reject PPL's "fictional leverage" adjustment:

> - The comparison of market value capital structures and book value capital structure to measure financial risk differences, is not supported in the literature of finance;
>
> - There is no financial risk difference between market value and book value capital structures because

interest expense (the actual source of financial risk) doesn't change, regardless of the capital structure measurement perspective;

- One company cannot have two levels of financial risk (i.e., one based on book value and one based on market value);

- The DCF model does not "mis-specify" the cost of equity when market prices are different from book value, and utilities are able to attract capital on reasonable terms absent any so-called "leverage" adjustment;

- Moul's "leverage" adjustment is, fundamentally, a market-to-book ratio adjustment, and this Commission has rejected market-to-book ratio adjustments in the past;

- The "leverage" adjustment is based on the "fair value" of the capital employed in financing the utility operation, as such it is a surrogate for "fair value" rate base, which results in a revenue requirement higher than that required by law in a regulatory jurisdiction in which rates are to be based on original cost (depreciated book value);

- A utility market price significantly above book value indicates that investors expect that firm to earn a return above its cost of equity, but according to Mr. Moul's "leverage" adjustment the higher the market price, the greater the upward adjustment necessary, which would exacerbate the over-recovery;

- The "leverage" adjustment recommended by Mr. Moul has been presented in dozens of regulatory jurisdictions. It has been rejected by all of those jurisdictions (including, recently, Pennsylvania).

OCA St. 2-SR at 11. The OCA submitted that for the reasons just discussed, and taking the record as a whole, such an adjustment should not be considered in this matter. OCA M.B. at 60-64.

ii. ALJ's Recommendation

For the reasons developed by the OCA and I&E, the ALJ recommended that the Company's leverage adjustment be denied. R.D. at 76.

iii. Exceptions

PPL excepts to the ALJ's rejection of its proposed leverage adjustment, noting that the Commission has accepted a leverage adjustment in a number of cases, including PPL's last fully litigated rate case in 2004, where the Commission adopted a forty-five basis point adjustment. PPL avers that the ALJ appears to conclude that the OCA's and I&E's criticisms of the leverage adjustment are a basis to reject the leverage adjustment, despite the fact that it has been accepted on numerous occasions in the past and each of these criticisms have been offered in the past. PPL points out that the principal criticism offered by the OCA and I&E is that there is no risk difference between a capital structure where equity is valued at market as compared to book prices, because the amount of interest that must be paid on debt remains the same. PPL opines that the error of this argument is that the interest amounts are greater as a percentage of book equity capitalization than they are as a percentage of market equity capitalization. Therefore, asserts PPL, the risk of debt payments is less as a percentage of market equity capitalization than it is at book equity capitalization. PPL states that because the DCF sets the equity cost rate at market capitalization, it understates the investor cost rate when applied to the rate base. According to PPL, the ALJ erred in declining to include a leverage adjustment when relying solely on the DCF analysis to arrive at the recommended cost of equity. PPL Exc. at 11-16.

In reply, the OCA states that the ALJ was correct to reject the leverage adjustment, as she accepted the fact that artificially increasing the ROE based on a technique that finds no support in the financial literature, does not represent sound ratemaking. Additionally, the OCA avers that PPL's leverage adjustment has been thoroughly reviewed and rejected in virtually every regulatory jurisdiction where it has been proposed, noting that since 2007, PPL's witness has testified in twenty-four regulatory jurisdictions, and none has specifically accepted and utilized the "leverage/risk" adjustment. According to the OCA, there is no need for a leverage adjustment within the confines of standard regulatory practice or a need for such a mechanism in Pennsylvania. OCA R. Exc. at 8-10.

In its Reply Exceptions, I&E asserts that the leverage adjustment is wholly discretionary and, in this case, fundamentally unnecessary, not only for the reasons directly noted by the ALJ, but also because PPL's inputs into its 9.68% DCF calculation are already overstated. Further, I&E opines that today's investment market does not support PPL's ROE. According to I&E, both PPL's calculated growth and dividend rates within its DCF analysis already provide the equity boost that PPL seeks through its leverage adjustment. I&E explains that the PPL 5% growth rate was based on its average barometer group growth rates, which were flawed in I&E's opinion because they did not satisfy even its own criteria. I&E submits that though accepting its unadjusted growth rate of 4.79%, the ALJ nonetheless arrived at a calculated return on equity of 9.6%, the same DCF return calculated by PPL using inflated growth rates. I&E avers that because PPL's DCF calculation already has inflated inputs, a further upward boost from the leverage adjustment is unnecessary. I&E R. Exc. at 19-20.

iv. Disposition

Based upon our analysis of the evidence of record, we are persuaded by the arguments of the OCA and I&E that PPL's requested leverage adjustment is not reasonable and should be denied. The fact that we have granted leverage adjustments in a few select cases in the past as noted by PPL does not mean that such adjustments are warranted in all cases. The award of such an adjustment is not precedential but discretionary with the Commission. In fact, the Commission has rejected leverage/financial risk adjustments that are similar to the one proposed by PPL in this proceeding. *See, e.g., Pa. PUC v. Aqua Pennsylvania, Inc*., Docket No. R-00072711, at 38-39 (Order entered July 31, 2008). Moreover, in the context of our determination, *supra*, of a reasonable return on equity for PPL of 10.28%, we conclude that there is no need to have an artificial upwards adjustment to compensate for any perceived risk related to PPL's market-to-book ratio. Accordingly, we shall deny the Exceptions of PPL and adopt the ALJ's recommendation to reject PPL's requested leverage adjustment.

g. Risk Adjustment

i. Positions of the Parties

PPL proposed a 120 basis point upward adjustment because the Company believes that as the size of a firm decreases, its risk and, hence, its required return, increases. Further, PPL used the SBBI Yearbook to argue that the returns for stocks in lower deciles had returns in excess of those shown by the simple CAPM. PPL St. 11 at 54-55.

Alternatively, I&E charged that PPL's rate of return recommendations are also grossly overstated by its assignment of several faulty assumptions of risk to PPL. I&E noted:

> While some technical market literature supports adjustments relating to a company's size, in a critical point of distinction, this literature is *not* specific to the utility industry. On the other hand, utility-specific academic literature specifically argues against a size adjustment for utilities. A specific study of utility stocks and the size effect concluded as follows:
>
> The objective of this study is to examine if the size effect exists in the utility industry. After controlling for equity values, there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not for utility stocks. This implies that although the size phenomenon has been strongly documented for the industrials, the findings suggest that *there is no need to adjust for the firm size in utility rate regulation*.[17]

As to unpredictability, I&E stated that "one cannot expect risky companies to always outperform less risky companies; otherwise they would not be risky." I&E M.B. at 101-103.

ii. ALJ's Recommendation

The ALJ recommended that PPL's proposed size adjustment be denied. R.D. at 82.

iii. Exceptions

No Party filed Exceptions on this issue with regard to the ALJ's recommendation. Finding the ALJ's recommendation to be reasonable, we adopt it without further comment. Accordingly, PPL's proposed size adjustment is denied.

---

[17] I&E M.B. n. 220; I&E St. 1 at 55, citing Dr. Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of Midwest Finance Association*, 1993, at 95-101 (emphasis added), reproduced in I&E Exh. I, Sch. 15.

h. Management Effectiveness Adjustment

i. Positions of the Parties

PPL included a twelve basis points management effectiveness adjustment to its return on equity claim. Both I&E and the OCA oppose any allowance for management effectiveness.

The Company summarized its evidence in support of this adjustment as follows:

> PPL Electric's management is effectively controlling costs, while at the same time, providing customers with high quality service and expanded service options. As detailed in the Statement of Reasons, the Company has taken substantial efforts to improve productivity and manage costs, including, but not limited to: (1) new technology to improve productivity and including advanced meters; (2) a smart grid distribution automation system, which will provide direct reliability benefits to over 60,000 customers in the project area and lead to increased reliability benefits to all customers by providing system operators advanced and timely situational awareness and control capabilities through a wider deployment throughout PPL Electric's service territory; (3) a work and asset management system, which is a new large scale software solution that will improve associated work management business processes in order to more effectively and efficiently manage the portfolio of work; (4) several initiatives to improve storm processes including call handling time and volume; (5) increased investment to address aging infrastructure, which will have a positive, long-term benefit in controlling reactive operating costs; and (6) capital investment in information systems to support customer choice and to provide expanded self-service options for customers, which improves service to customers while controlling operating costs. In addition, the Company is testing and evaluating a variety of applications and features that will expand the capabilities of the current system and equipment over the next five years.

PPL M.B. at 116-117.

I&E argued that the twelve basis points sought by PPL translates into an additional $3 million in rate revenues. Tr. at 335; I&E M.B. at 116. I&E argued further that there is considerable room for improvement in several areas, including preventable major outages, customer service calls answered within thirty seconds, the number and percentage of bills not rendered to residential customers and small businesses, and the number of disputes with no response within thirty days. I&E M.B. at 119-120. As I&E saw it, PPL's requested twelve basis point upward adjustment to the cost of equity is neither warranted nor supported. I&E opined that it should be rejected. I&E M.B. at 123.

The OCA agreed with I&E. The OCA referred to the $832,000 that PPL has either agreed to pay or was ordered to pay in fines and penalties. OCA M.B. at 65.

ii. ALJ's Recommendation

The ALJ stated that PPL presented substantial evidence of management effectiveness in a number of areas, including advanced metering infrastructure, operating initiatives, customer contact center, customer education, energy efficiency programs, and customer assistance programs. According to the ALJ, the provision of safe, reliable, adequate and reasonable service is the minimum required by the Code, and simply meeting that standard does not warrant excessive rewards. However, the ALJ concluded that the actions taken by PPL in its response to Commission initiatives, and in providing excellent, albeit imperfect, service, in meeting the needs of its ratepayers and customers, merited a management effectiveness increase of six basis points. R.D. at 89

iii. Exceptions

In its Exceptions, PPL notes that the ALJ correctly summarized PPL's evidence presented to support its management performance adjustment. However, PPL criticizes the ALJ for recommending a six basis point adjustment in lieu of its twelve basis point request, as she relied on certain criticisms of PPL where the Company agreed to negotiate payments to resolve certain alleged violations of the Code or Commission Regulations. PPL avers that these limited circumstances do not provide a basis for denying PPL's requested twelve basis point adjustment to the cost of equity. PPL Exc. at 19.

The OCA excepted to the ALJ's recommendation, stating that the ALJ erred by awarding any management performance bonus as the evidence of record does not support such a conclusion. The OCA maintains that all regulated utilities in Pennsylvania are required to provide safe, adequate, reasonable and efficient service as a matter of law. 66 Pa. C.S. § 1501. The OCA avers that a utility must be doing more than providing efficient and reasonable service in order to receive more than the indicated rate of return. The OCA references its Cross Exhibit 1, which listed five separate dockets where the Commission's Prosecutory Staff had investigated PPL for potential violations of the Code and avers that such actions do not support the award recommended by the ALJ. OCA Exc. at 15-18.

I&E also excepted to the ALJ's recommendation, alleging that it is not supported by the evidence. I&E avers that PPL selectively presented evidence of "high quality" service and alleges that PPL essentially sought an investor reward for implementing statutorily-mandated programs that were purely ratepayer funded through Commission-mandated rates that guaranteed PPL recovery with interest through separate surcharges and riders. I&E opines that while the Commission has the discretion to reward management, because such action essentially sanctions approval of a ratepayer premium, the Commission should exercise that discretion circumspectly. According to I&E, circumstances warranting investor rewards should be the exception not the norm.

I&E opines that PPL's service is not exceptional, finding instead that it was at times above average, at other times below average, and sometimes just average. According to I&E, PPL presented no clear evidence of any particular shareholder commitment that justifies gratuitous ratepayer funding. I&E Exc. at 23-26.

In reply, PPL states that clearly a public utility has a statutory duty to provide adequate, efficient, safe and reasonable service at just and reasonable rates. However, PPL posits that it is the efforts and manner in which the utility meets the statutory requirements that the Commission considers when determining if a management performance adder is appropriate. For example, PPL provides that the Commission awarded a twenty-five basis point adder to compensate a utility where it "promoted and accomplished cost efficiencies in several operational aspects". PPL R.Exc. at 9 (citing *Pa. PUC v. West Penn Power Co*., 1994 Pa. PUC Lexis 144 at *147). Similarly, PPL notes that the Commission awarded a twenty-two basis point adder where a utility's "managerial performance related to its water quality, customer service and low income program continues to be laudable." PPL R.Exc. at 8-9 (citing *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket No. R-00072711, at 50 (Order entered July 31, 2008)).

PPL avers that in this proceeding, I&E and the OCA ignore the record evidence of the exceptional manner in which PPL has exceeded its statutory obligation to provide adequate, efficient, safe and reasonable service and facilities at just and reasonable rates. According to PPL, the record evidence demonstrates that PPL's management is effectively controlling costs, while at the same time, providing customers with high quality service and expanded service options. In response to the Parties' allegations with regard to the five instances over the last four years where PPL paid a civil penalty, PPL responds that these parties overlook that PPL has 1.4 million customers and has millions of interactions with these customers annually. PPL points out that in only four instances has any penalty been applied, and in three of those cases the Company settled the matter without any finding of any violation. PPL submits that in only one instance in the past four years has it been found to have violated the Code, and on that occasion, it was assessed a civil penalty of $100. Given the Company's efforts, PPL opines that the requested twelve basis point adder clearly is modest and within the range previously awarded by the Commission. PPL R.Exc. at 9-10.

In its Replies to Exceptions, the OCA notes its continuing opposition to the management performance bonus in its entirety and requests that the Commission modify the ALJ's recommendation and remove the six basis point ROE adder. OCA R.Exc. at 14.

In its Replies to Exceptions, I&E similarly notes that PPL's evidence does not support any management bonus. I&E R.Exc. at 17.

iv. Disposition

Pursuant to the Code, the Commission may reward utilities through rates for their performance. In pertinent part, Section 523 of the Code, 66 Pa. C.S. § 523 provides:

> **§ 523. Performance factor consideration.**
>
> (a) **Considerations.** – The Commission shall consider, in addition to all other relevant evidence of record, the efficiency, effectiveness and adequacy of service of each utility when determining just and reasonable rates under this title. On the basis of the commission's consideration of such evidence, it shall give effect to this section by making such adjustments to specific components of the utility's claimed cost of service as it may determine to be proper and appropriate. Any adjustment made under this section shall be made on the basis of specific findings upon evidence of record, which findings shall be set forth explicitly, together with their underlying rationale, in the final order of the commission.

> (b) **Fixed utilities.** – As part of its duties pursuant to subsection (a), the commission shall set forth criteria by which it will evaluate future fixed utility performance and in assessing the performance of a fixed utility pursuant to subsection (a), the commission shall consider specifically the following:
>
> (1) Management effectiveness and operating efficiency as measured by an audit pursuant to Section 516 (relating to audits of certain utilities) to the extent that the audit or portions of the audit have been properly introduced by a party into the record of the proceeding in accordance with applicable rules of evidence and procedure.
>
> * * *
>
> (4) Action or failure to act to encourage development of cost-effective energy supply alternatives such as conservation or load management, cogeneration or small power production for electric and gas utilities.
>
> * * *
>
> (7) Any other relevant and material evidence of efficiency, effectiveness and adequacy of service.

Based upon our analysis of the evidence of record, we are persuaded by the arguments of the Company that its management performance related to its advanced metering infrastructure, operating initiatives, customer contact center, electric competition, customer education, energy efficiency programs, and customer assistance programs is laudable and warrants consideration as a factor in our final cost of equity allowance. Accordingly, we shall grant PPL's Exception and adopt its twelve basis point management effectiveness adjustment to our prior return on equity recommendation in recognition of its exemplary managerial performance. In the context of the evidentiary record developed in this proceeding, we conclude that this adjustment is reasonable, appropriate and conservative based on Section 523 of the Code and the similar allowances in the prior Commission decisions cited by the Company. The ALJ's recommendation of a six basis point allowance shall be modified, consistent with the foregoing and the Exceptions of I&E and the OCA are denied.

i. Summary on Common Equity

i. Positions of the Parties

As noted above, there are four methods of determining the cost of equity: DCF, RP, CAPM, and CE. PPL relied on each of these methodologies in presenting its recommended return on equity of 11.25%.

I&E argued that equal weight should not be given to the four different methodologies as PPL did in its evaluation.

Both the OCA and I&E took issue with the Company's analysis in arriving at the proposed cost of equity and capital structure. The OCA pointed out that the Commission has indicated a preference for using the DCF method to establish reasonable common equity costs.

While calculating average returns on equity for its respective groups of 11.13% and 11.43%, PPL's indicated cost of common equity reflects an upward adjustment of seventy basis points for its EDG and 118 basis points for its IEG to account for the leverage claim. It further reflects an upward adjustment of 120 basis points for both EDG and IEG to reflect its claim that PPL has higher business risk due to its small size relative to its proxy group. Finally, the indicated cost of common equity reflects PPL's upward adjustment of another twelve basis points to reflect PPL's requested award for claimed management efficiency.

I&E opposed PPL's calculated return on equity for several reasons. First, I&E averred that PPL's selected barometer group was flawed in that several of its selections failed to meet PPL's own purportedly objective selection criteria. Second, I&E maintained that PPL gave undue weight to the RP and CE methods. Third, I&E claimed that PPL employed an inflated DCF growth rate and a dividend yield adjustment that was unnecessary. Fourth, according to I&E, PPL employed inflated CAPM betas. Finally, I&E rejected PPL's extra-method adjustments for leverage, size (business risk), and management efficiency as they are unsupported and inappropriate.

ii. ALJ's Recommendation

The ALJ concluded that the Commission's preferred method of determining a utility's ROE is the DCF model. Consequently, the ALJ recommended adoption of I&E's DCF analysis, consisting of a dividend yield of 4.89% and a growth rate, prior to I&E's log-linear adjustment, of 4.79%. Additionally, the ALJ recommended adoption of a six basis point adjustment to PPL's ROE for management effectiveness. The result of the ALJ's recommendations equates to an overall ROE of 9.74%. R.D. at 93.

iii. Disposition

The ALJ recommended that the Company's position of an actual capital structure consisting of 49.22% long-term debt and 50.78% common equity along with a long-term debt cost rate of 5.50% be adopted. Additionally, the ALJ recommended adoption of the I&E position on PPL's cost of equity capital of 9.74%. According to the ALJ, the evidence overwhelmingly demonstrated that PPL's claim for a return on equity of 11.25% and an overall rate of return of 8.47% overstated what reasonable investors should expect from a regulated public utility and is not necessary for PPL to safely and reliably provide electric distribution service to its captive ratepayers. Based on these recommendations, the resulting overall rate of return per the ALJ is 7.65%.

Capital Type	Ratio (%)	Cost Rate (%)	Weighted Cost (%)
Debt	49.22	5.50	2.71
Equity	50.78	9.74	4.95
Total	100.00		7.65

R.D. at 93-94.

Based upon the foregoing, we conclude that PPL's capital structure should be based upon the Company's actual capital structure of 49.22% debt and 50.78% equity. PPL's cost of equity capital is properly determined by the DCF analysis performed by the Parties, with other methods utilized as a check on the reasonableness of the DCF results. Accordingly, we adopt a cost of equity rate of 10.4%. In addition, the 10.4% approved ROE is inclusive of the twelve basis point management efficiency adjustment as requested by the Company. Each of the remaining PPL requested ROE adjustments are rejected as unreasonable.

The following table summarizes our final determinations concerning PPL's capital structure, cost of debt and cost of common equity, as well as the resulting weighted costs and overall rate of return of 7.99%:

Capital Type	Ratio (%)	Cost Rate (%)	Weighted Cost (%)
Debt	49.22	5.50	2.71
Equity	50.78	10.4	5.28
Total	100.00		7.99

F. Taxes – Gross Receipts Tax

1. Positions of the Parties

PPL's total FTY gross receipts tax (GRT) expense claim is $50.102 million, which consists of two components. The first component is a pro forma calculation of gross receipts tax for the FTY at present rates of $43.930 million. PPL Exh. Future 1, Sch. D-11 at 3. The second component is $6.172 million, resulting from the proposed rate increase. PPL M.B. at 133; PPL Exh. Future 1, Sch. D-12 at 6.

I&E recommended a total GRT allowance of $49.168 million, which is a $934,000 reduction to the Company's total claim. The recommendation consists of a pro forma allowance of $43.1 million and a rate increase allowance of $6.068 million, assuming a full rate increase. The recommended GRT adjustments are reductions of $830,000 to the pro forma claim and $104,000 to the rate increase claim. I&E's recommendation is based on the fact that PPL's tax liability for the GRT is limited to the actual revenues PPL receives. As such, I&E recommended that the GRT tax allowance in rates should be calculated using the net revenues collected by PPL. I&E M.B. at 69; I&E St. 2 at 46-48.

2. ALJ's Recommendation

The ALJ found that I&E's recommendation to calculate the GRT allowance using net revenues was reasonable and should be approved, because it is a better match of the claimed actual receipts of revenue that will produce the Company's actual GRT tax liability. R.D. at 95, 96; I&E St. 2 at 46-48. The ALJ stated that the Pennsylvania Department of Revenue (DOR) Corporation Tax Bulletin 2011-02, issued July 20, 2011 (Bulletin), confirmed that the Company's net uncollected revenues would not reduce its GRT tax liability. The ALJ also stated that the Company did not provide any evidence to support that the cost of documentation would exceed the overvaluation of GRT, and the

Company's witness confirmed that the Company maintains records of customers' bad debts. R.D. at 97.

3. Exceptions

In its Exceptions, PPL avers that its GRT should be recovered in full. PPL Exc. at 37. PPL states that the ALJ's recommendation should be rejected because it disregards changes in the calculations of GRT imposed by the DOR in the Bulletin. *Id*. at 37-38. PPL opines that the Bulletin makes use of the deduction from gross receipts for uncollectible accounts almost impossible. PPL explains that, under the Bulletin, its liability for GRT is no longer limited to actual revenues received, but, instead, PPL must file GRT using the accrual method of accounting. As such, a reduction against taxable gross income for an uncollectible account requires PPL to match each write-off to the tax period when the receipts are reported as taxable to Pennsylvania. PPL indicates that it does not have the capability to perform this tracking for the write-offs of amounts for its 1.4 million customers. *Id*. at 38; PPL St. 8-RJ, Part 1, at 36-37. PPL submits, while it is correct that it does maintain records of its customers' bad debts, this does not enable PPL to meet the onerous reporting and accounting requirements that the Bulletin requires. PPL Exc. at 38.

In its Replies to Exceptions, I&E argues that the ALJ correctly determined that the Bulletin confirmed I&E's adjustment to PPL's GRT claim on the basis that PPL's tax liability is the net of uncollectibles. I&E notes that, using the accrual methodology, PPL will deduct from its accrued billed revenues accounts that are written off. I&E asserts that PPL did not present any evidence to prove there are obstacles to it following the requirements in the Bulletin and distinguishing between billed and collected revenues. I&E R.Exc. at 24. I&E avers that, absent evidence that PPL pays taxes on uncollected revenues and that the cost of avoidance exceeds the benefit, the ALJ's decision should be adopted. *Id*. at 25.

4. Disposition

We agree with the ALJ's determination that I&E's recommendation to calculate the GRT allowance using net revenues is reasonable and should be adopted, as it is a better match of the claimed actual receipts of revenue that will produce the Company's actual GRT tax liability. The Bulletin supports I&E's adjustment on the basis that PPL's tax liability is billed revenues net of write-offs and recoveries. PPL will use the accrual method of accounting to deduct from its accrued billed revenues accounts that are written off. The Bulletin states the following, in pertinent part:

> If a taxpayer uses the accrual method of accounting to report its gross receipts, then the taxable gross receipts shall be calculated as follows:
>
> Billed revenues on an accrual basis (no reserves for bad debts)
> Less: Accounts actually written off for previously taxed Pennsylvania bad debts
> Plus: Collections of previously written off <u>Pennsylvania taxable bad debts</u>
>
> <u>Taxable Gross Receipts</u>

I&E Exh. 2-SR, Schedule 1, at 1.

Additionally, as PPL has explained, the Bulletin requires taxpayers claiming a deduction for bad debts to provide the DOR, upon request, with the following documentation: (1) the type and amount of receipts being written off; (2) the customer's location; and (3) the tax period during which the receipts were reported as taxable to Pennsylvania. *Id*. at 2. PPL submits that the DOR's reporting requirements are onerous and would require significant and costly changes to its billing and payment system. PPL M.B. at 134. Nevertheless, as I&E asserts, PPL has not presented any concrete evidence to show that it could not comply with the DOR's reporting requirements, such as cost analyses, evidence of system testing, or evidence of actual complexities. *See*, I&E Exc.

at 24; I&E M.B. at 70-71. PPL has also indicated that it does maintain records of customers' bad debts. Based on the evidence, we find that I&E's adjustment is reasonable. Accordingly, we shall deny PPL's Exception and adopt the ALJ's recommendation on this issue.

G. Rate Structure and Rate Design

This section of the Opinion and Order addresses cost of service, rate design and rate structure allocation issues. When a utility files for a rate increase, it must file a cost-of-service study (COSS) assigning to each customer class a rate based upon operating costs that it incurred in providing that service. 52 Pa. Code § 53.53; *Lloyd v. Pa. PUC,* 904 A.2d 1010, 1015 (Pa. Cmwlth. 2006). Public utility rates should enable the utility to recover its cost of service and should allocate this cost among its customers. These rates are required by statute to be just, reasonable and non-discriminatory. 66 Pa. C.S. §§ 1301, 2804(10).

1. Cost of Service Methodology

a. Positions of the Parties

PPL stated that the fundamental purpose of a cost allocation study is to aid in revenue allocation and the design of rates to be charged by identifying all of the capital and operating costs incurred by a utility to provide service to all of its customers, and then assigning or allocating those costs to individual rate classes on the basis of how those rate classes cause the cost to be incurred. PPL maintained that as a result of the *Lloyd* decision, *supra,* cost of service studies have assumed a greater degree of importance in utility ratemaking, but it still should be recognized that cost allocation is not an exact science, that there is no single correct cost allocation methodology and that the Court did not hold that all other considerations are to be disregarded. PPL M.B. at 136-137.

PPL presented a fully-allocated COSS, showing the allocation of its distribution costs among the various rate classes at both present and proposed rates for the historic (PPL Exh. JMK-1) and future (PPL Exh. JMK-12) test years. According to PPL, the filed COSS in this proceeding is virtually identical to the methodology adopted by the Commission in its 2010 base rate proceeding using the class maximum non-coincident peak (NCP) demand method, which is based on the highest demand imposed by each rate class on its distribution system, to allocate its demand-related distribution costs. PPL St. 8 at 19.

As in 2010, PPL's COSS utilized a "heightened" level of data analysis, using allocators to classify primary voltage level distribution facilities into their demand-related and minimum or no-load customer-related cost components. PPL stated that this method more accurately reflects cost causation than the method used in preceding rate cases, which allocated primary voltage level distribution facilities solely on the basis of demand. PPL St. 8-R at 9. PPL stated that prior to its 2010 case, the Company's cost allocation studies were criticized because not all of the primary voltage level distribution facilities used in its minimum size system studies had been classified into their applicable customer related and demand related components. PPL claimed that this modification is consistent with the National Association of Regulatory Commissioners (NARUC) Electric Utility Cost Allocation Manual (Manual) recommendations "that primary voltage level overhead and underground conductors be classified into their demand-related and customer-related cost components." *Id.;* PPL M.B. at 137-138.

Only the OCA opposed the Company's COSS, and on substantially the same grounds as it opposed the Company's COSS in the last base rate case. The OCA argued that primary plant should be classified on a 100% demand basis, with only secondary plant allocated to both demand and customer components. OCA St. 3 at 18. The OCA presented density studies which it claimed do not support allocation of distribution plant based on customer count. As a "compromise" position, OCA recommended that the Commission allocate 100% of primary plant on a demand basis and apply the OCA's minimum size study to allocate secondary plant on a customer and demand basis. OCA M.B. at 77-82.

The OCA further argued that the Parties have misinterpreted the Commission's 2010 Order that NARUC has updated its cost of service principles since issuing the 1992 NARUC Manual, and argued that its recommendation reflects a compromise. OCA R.B. at 33-38.

The OSBA, PPLICA and REG supported PPL's position on COSS allocation and believe that it is consistent with the NARUC Manual and reflects a more realistic operation of PPL's system than the OCA counterproposal.

The OSBA stated that its primary focus in this case has been to determine whether the COSS presented by the Company conformed to the COSS approved by the Commission in the 2010 base rate case. The OSBA concluded that it did, and therefore, there was no need to re-litigate it in this proceeding. OSBA M.B. at 7.

REG agreed with the Company's classification of distribution plant as partially customer-related and partially demand-related, and the Company's allocation of the plant. This, REG argued, is consistent with the Commission's disposition of the Company's last rate case as well. REG M.B. at 4-5.

PPLICA argued in favor of the Company's COSS, which it believed properly allocates primary distribution facilities costs in both a customer and demand component and is consistent with NARUC policies. PPLICA characterized the OCA approach as "a results-driven density analysis with no meaningful relation to the cost of service principles historically applied by the Commission and supported by NARUC."

PPLICA M.B. at 7. PPLICA averred that PPL's COSS provides a reasonable basis for assessing distribution-related rates of return for each rate schedule, consistent with Commission precedent and NARUC recommendations. *Id.* at 8.

According to PPLICA, there are two recognized methodologies to estimate the customer component of distribution costs: (1) the minimum intercept method; and (2) the minimum size method, which is the method used by PPL. Each is designed to estimate the component of distribution plant cost incurred by a utility to connect a customer to the system. The minimum size method is designed to reflect costs associated with changes in both the number of distribution customers and the loads of these customers. It reflects a classification of the distribution facilities that would be required to simply interconnect a customer to the system, regardless of the kW load of that customer. PPLICA St. 1-R at 4-5; PPLICA M.B. at 9.

b. ALJ's Recommendation

The ALJ concluded that the other Parties rejected the OCA's arguments most persuasively. For the reasons set forth above by the Parties, the ALJ recommended that the Company's COSS be approved, and the OCA alternative be denied. R.D. at 108.

c. Exceptions

In its Exceptions, the OCA opines that the ALJ erred in recommending the use of PPL's COSS to allocate the revenue increase. The OCA avers that the PPL COSS is flawed because it does not accurately reflect cost causation, is inconsistent with the 1992 NARUC Manual and the updated NARUC Report, and is inconsistent with the historical method that PPL used prior to 2010. The OCA submits that, prior to 2010, PPL classified primary distribution plant as 100% demand related and further classified secondary distribution plant as partially demand and partially customer related.

According to the OCA, this method was approved by the Commission in the 2004 and 2007 PPL rate cases, and is the same COSS method that the OCA has proposed in the present case. The major change, starting with the 2010 case, is that PPL now classified primary distribution plant as 63% customer related and 37% demand related. This change, avers the OCA, has caused over one billion dollars of such costs to be shifted from a demand basis to a customer count basis. OCA Exc. at 18-19.

Next, the OCA notes that the ALJ relied on the arguments of the Company and the other Parties in adopting PPL's COSS, whereby the central point made was that the Commission had already ruled against the OCA in PPL's 2010 rate case and should do the same here. The OCA avers that PPL's COSS method does not follow the 1992 NARUC Manual in many respects, and is inconsistent with the more recent 2000 NARUC Report. The OCA states that in the 2010 rate case, PPL's recommended allocation of the entire increase to the residential class was adopted by the Commission, partially because the Commission found the OCA's approach did not accurately reflect the costs incurred to serve the residential class. *Id*. at 20 (citing *Pa. PUC v. PPL Electric Utilities Corporation*, Docket No. R-2010-2161694, at 46 (Order entered December 21, 2010) (*PPL 2010*)). However, the OCA avers that in the 2010 case its approach was identical to PPL's own COSS method used in 2004 and 2007. According to the OCA, PPL's proposed COSS in the instant proceeding contains bias to the residential class that negates any possibility of that class reaching "cost of service" anytime in the foreseeable future. OCA Exc. at 19-20.

Additionally, the OCA maintains that both primary and secondary distribution plant should be classified as 100% demand related, consistent with how regulatory bodies in over thirty states classify such plant. The OCA avers that it has recommended a reasonable and appropriate compromise COSS that maintains a customer/demand split for the secondary distribution plant but allocates primary plant on demand only, which is exactly what PPL did prior to 2010. Further, the OCA then classified secondary distribution plant as partially demand and partially customer related, just like PPL's current and prior COSSs, but with a more appropriate customer component than PPL based on its revisions to PPL's minimum size study and consistent with how such a study is to be performed as per the 1992 NARUC Manual. OCA Exc. at 20-21.

The OCA submits that the ALJ's and other Parties' reliance on *PPL 2010* is misplaced as the Commission has substantial evidence in this record that it did not have in 2010, specifically: (1) PPL's proposed COSS is an outlier in its classification of primary distribution plant as having a customer component; (2) to the extent that a customer component should be a part of distribution plant cost assignment, PPL's minimum size study fails to follow the 1992 NARUC Manual's specific instructions for performing such a study; and (3) the fact that adhering to PPL's proposed COSS will always result in the residential class being allocated a substantial portion of future rate increases with little to no hope of ever achieving cost of service. OCA Exc. at 21.

The OCA maintains that using the method that has been accepted in over thirty states, a 100% demand allocation, the indexed rate of return for the RS class, at present rates, would be 124%. Using the method that PPL proposed in this proceeding, the indexed rate of return for the RS class would be only 63%, per the OCA. The OCA avers that its compromise position, 100% demand allocation only for primary plant, shows the Residence Service (RS) class at an indexed rate of return of 112% at present rates. Therefore, according to the OCA, at current rates under an accurate and reasonable COSS, the RS class is paying more than its cost to serve. As a result, the OCA avers that the Commission's holding in *PPL 2010* should not be controlling here. OCA Exc. at 23-24.

In reply, PPL states that its COSS is virtually identical to the methodology adopted by the Commission in the 2010 base rate proceeding, which was fully litigated on this issue. PPL avers that the Commission fully considered and rejected the OCA's proposal in the 2010 base rate proceeding and that the OCA has offered no change in law or fact that would warrant a departure from that decision. PPL maintains that the ALJ properly approved its COSS. PPL R.Exc. at 16.

In its Replies to Exceptions, the OSBA first notes that, contrary to the OCA's argument, PPL has actually proposed to reduce the customer component of distribution plant costs in the instant proceeding relative to the method that was explicitly approved by the Commission in the Company's 2010 case, to the benefit of residential customers. The OSBA avers that for the OCA to prevail on the issue of cost allocation, it must demonstrate both that the Commission erred in its decision in the 2010 case to allow for the classification of primary system distribution plant costs into both demand and customer components and that the Commission has consistently erred over the past decades in approving PPL's cost classification methodology for secondary distribution system costs. The OSBA notes that the Commission considered virtually all of the evidence presented by the OCA in this proceeding in the 2010 case and rejected the OCA's conclusion. Moreover, the OSBA notes that, in objecting to PPL's method for classifying secondary system plant costs, the OCA is challenging an approach PPL has used for years if not decades. According to the OSBA, in the OCA's view, Commission precedent prior to 2010 is relevant only if it favors residential customers, which is both wrong and inconsistent. OSBA R.Exc. at 4-6.

In response to the OCA's assertion that regulatory bodies in thirty states do not include any customer component in classifying either primary system or secondary system distribution costs, the OSBA states that cost allocation is often hotly debated among the parties to a regulatory proceeding. The OSBA explains that the economic issue of the classification of distribution plant costs is essentially an issue involving residential and small to medium business customers, as large industrial customers are generally served at transmission voltage and have no stake in this issue. According to the

OSBA, the smaller business customers are generally unrepresented in utility regulatory proceedings, so it is unclear whether the regulatory pattern alleged by the OCA results from hard cost analysis, or simply a lack of representation. The OSBA maintains that in either event, the thirty jurisdictions are ignoring the basic principle that this Commission has accepted. As this principle has long been followed in Pennsylvania, the OSBA submits that the alleged practices of other jurisdictions are irrelevant. OSBA R.Exc. at 6-7.

Next, the OSBA submits that the OCA characterization of the "updated NARUC report" as an update to the 1992 NARUC Cost Allocation Manual is deceptive at best. The OSBA explains that the 1992 NARUC Manual was published as a NARUC Report. The report to which the OCA refers to as an update is nothing of the kind, but, in fact, a report prepared by the Regulatory Assistance Project entitled "Charging for Distribution Utility Services: Issues in Rate Design." The OSBA avers that this document contains little in the way of specifics for distribution cost classification and allocation and does not necessarily reflect the positions of NARUC. As a result, the OSBA recommends that the Commission give no weight to this consultant's report. OSBA R.Exc. at 7-8.

In its Replies to Exceptions, PPLICA states that PPL's proposed COSS is firmly supported by NARUC principles, designed to achieve cost of service rates and should be approved. PPLICA points out that while the OCA refers to the updated report as a "NARUC" report, the document is not an official NARUC publication. Also, PPLICA states that the OCA's claim that this document establishes PPL's minimum size system COSS as an outlier is specious. According to PPLICA, this report's statement that allocating primary distribution plant on a 100% demand basis "is used in more than thirty states" dates back to 2000, almost thirteen years ago. PPLICA avers just as PPL classified primary distribution plant on a 100% demand basis before updating its classification methods in 2010, many of the states referenced in the report may have modified their methodologies. Therefore, PPLICA asserts that the Commission should not accord significant weight to stale data. PPLICA R.Exc. at 4-5.

PPLICA further replies that PPL's minimum size study is completely consistent with the NARUC Manual, and that it is worth noting that the same study employed by PPL in this proceeding was fully litigated in the Company's 2010 case and adopted by the Commission. Additionally, PPLICA notes that PPL's minimum size study reflects the Company's actual installations rather than the theoretical adjustments applied by the OCA. Lastly, PPLICA argues that PPL's proposed COSS contains no inherent bias towards any rate class as alleged by the OCA. PPLICA R.Exc. at 5-7.

d. Disposition

Based upon our review of the record evidence, we are in agreement with the ALJ that PPL's proposed COSS should be approved. It is important to note that the PPL COSS methodology is supported by all the Parties which offered a position on this issue, with the exception of the OCA. We have reviewed the OCA's position and Exceptions on this issue and are not persuaded by the arguments it presented in support of its recommended COSS methodology. The position presented by the OCA was considered and rejected by the Commission in the litigation of PPL's 2010 base rate proceeding. *Pa. PUC v. PPL Electric Utilities Corp*., Docket No. R-2010-2161694, at 46 (Order entered December 21, 2010). We conclude that the OCA has not presented convincing arguments in this proceeding that would cause us to re-evaluate our determination in PPL's prior proceeding. PPL's proposed COSS in the instant proceeding is virtually identical to the COSS approved in 2010, is consistent with the NARUC Manual and more accurately reflects cost-causation principles than the COSS methodology the Company utilized prior to the 2010 base rate case. We conclude that PPL has carried its burden of proof on this issue, and we shall adopt the ALJ's recommendation. Accordingly, we shall deny the Exceptions of the OCA.

2. Revenue Allocation

a. Positions of the Parties

PPL explained that its proposed allocation of revenue requirement among the various rate classes in this proceeding is driven largely by the Commonwealth Court's decision in *Lloyd, supra.* PPL stated that this case is the fourth in a series that have purportedly attempted to move PPL's distribution rates to true cost of service. PPL St. 5 at 8. The Company sought to establish cost of service, and then to apply those costs to the appropriate rate schedules. Because that approach produced a distribution rate increase to customers served under Rate Schedule Residential Thermal Storage (RTS) of about 165 percent, which PPL considered to be unjust and unreasonable, it developed an alternative allocation, which limited the increase to Rate RTS from 165% to approximately 78%. According to PPL, the goal was to bring all rate classes closer to the system average rate of return, while still considering the principle of gradualism. *Id.* at 10; PPL M.B. at 152-153.

The Company's proposal is as follows:

	Relative Rate of Return	
Rate Classes	**Present Rates**	**Proposed Rates**
RS	63.03%	83.81%
RTS	-65.31%	23.05%
GS-1	133.55%	99.05%
GS-3	285.18%	196.34%
LP-4	163.36%	118.44%
LP-5	-90.72%	98.94%
LPEP	353.09%	256.26%

GH-2	86.64%	103.55%
SL/AL	100.49%	99.65%
Total	100%	100%

PPL Exh. JMK-2 at 8-11; PPL M.B. at 154.

The OCA stated that for the second time in two years, PPL has proposed to allocate nearly the entire revenue increase to the RS and RTS rate classes. The OCA noted that of PPL's $104.6 million increase requested, PPL proposed to allocate over $99 million to the residential class with over $3.5 million of that amount allocated to RTS customers. The OCA averred that these increases amount to an annual increase to distribution rates of 20.9% and 77.6%, respectively. OCA M.B. at 66.

The OCA recommended an alternative revenue allocation that it claims reflects the results of a properly conducted, reasonable and equitable cost of service study. The OCA submitted that while cost of service should guide the Commission when setting rates in this proceeding, other ratemaking principles such as gradualism, avoidance of rate shock and basic fairness must not be abandoned. As such, the OCA recommended that no rate class receive a revenue decrease and that no class sustain an increase greater than 150% of the system-wide percentage increase, or no more than 21.45%. *Id.* at 95.

The OCA's proposal results in the following indexed rate of returns by class:

Relative Rate of Return

Rate Classes	Present Rates	Proposed Rates
RS	112%	111%

RTS	-93%	-53%
GS-1	180%	131%
GS-3	104%	109%
LP-4	-13%	11%
LP-5	-88%	-4%
LPEP	399%	289%
GH-2	30%	50%
SL/AL	90%	111%
Total	100%	100%

OCA St. 3 at 37, 41; OCA M.B. at 96-97. According to the OCA, this proposed revenue allocation results in a reasonable movement of all classes to cost of service at PPL's proposed revenue increase, while also recognizing the need for gradualism. OCA M.B. at 97.

REG and PPLICA supported PPL's proposed revenue allocation as consistent with the COSS. According to these Parties, the Company's proposed revenue allocation moves all rate classes closer to cost of service in accordance with the Company's COSS and consistent with *Lloyd*. REG M.B. at 5; PPLICA M.B. at 13-17.

PPLICA pointed out that Rate Schedule LP-5 customers will experience a 59.1% increase, and although Rate Schedule LP-4 customers do not experience an increase, their current rates remain above cost of service. PPLICA recognized that the movement towards actual cost of service rates as set forth is reasonable, and did not oppose this allocation. PPLICA M.B. at 16.

PPLICA argued that the Commission should not give any credence to OCA's COSS, and as the OCA's proposed allocation is based on its flawed COSS, neither should the Commission give any credence to the OCA's recommendation. PPLICA St. 1-R at 8; PPLICA M.B. at 15.

b. ALJ's Recommendation

The ALJ concluded that as the OCA alternative was based on its COSS, and not on the Company's, which she recommended be adopted, the OCA alternative should be denied. The ALJ recommended adoption of the Company's revenue allocation, with the actual numbers to be based on the proportionate adoption of the actual revenue requirement approved. R.D. at 110.

c. Exceptions

In its Exceptions, the OCA submits that its COSS should be adopted as a guide to set rates in this proceeding and for purposes of establishing a fair and reasonable allocation of the revenue increase. The OCA avers that PPL's COSS is unduly discriminatory against residential customers and PPL's proposed revenue allocation is based on that study. The OCA maintains that its proposed allocation is based upon a more reasonable COSS and recognizes gradualism and fairness and caps increases to any one rate class at no greater than 150% of the system-wide percentage increase, or 21.45%. The OCA opines that its revenue allocation method results in a reasonable movement of all classes to cost of service at PPL's proposed revenue increase, while also recognizing the need for gradualism. OCA Exc. at 31-34.

In reply, PPL states that its proposed revenue allocation follows the Company's COSS and substantially moves all rate schedules toward the system average rate of return. PPL avers that since the OCA's revenue allocation is premised on its flawed COSS, its resulting revenue allocation was properly rejected by the ALJ. PPL R. Exc. at 16-17.

In its Replies to Exceptions, the OSBA points out that, as the OCA readily admits, the adoption of the OCA's revenue allocation proposal requires the Commission to agree to the OCA's version of the COSS. According to the OSBA, because the ALJ correctly rejected the OCA cost allocation methodology, the OCA's revenue allocation methodology should similarly be rejected. OSBA R.Exc. at 13-14.

In its reply, PPLICA states that the OCA's proposed COSS is contrary to Commission precedent and unsupported by the NARUC Manual and, as such, any revenue allocation based on the OCA's proposed COSS must be summarily rejected. In response to the OCA's argument about gradualism, PPLICA acknowledges that gradualism is a legitimate ratemaking construct designed to mitigate unreasonable rate increases. However, according to PPLICA, because PPL's COSS shows that residential customers are paying rates significantly below cost-of-service, PPL's revenue allocation limits gradualism adjustments to ensure that customers paying above-cost rates move reasonably closer to cost-of-service. PPLICA posits that as the ALJ's recommendation to approve PPL's revenue allocation incorporates gradualism, it should be approved by the Commission without modification. PPLICA R.Exc. at 9-10.

d. Disposition

Based upon our prior determination and discussion, *supra,* with respect to the rejection of the OCA COSS, we are in agreement with the ALJ that PPL's proposed revenue allocation should be approved. As the OCA's revenue allocation recommendation is based upon its COSS, which we have rejected, we conclude that its allocation proposal should similarly be denied. Additionally, we find that PPL's revenue allocation proposal is consistent with *Lloyd,* moves all rate classes closer to cost of service in a reasonable manner and considers the principle of gradualism. Accordingly, we shall adopt the recommendation of the ALJ and deny the OCA Exceptions on this issue.

3. Revenue Scaleback

a. Positions of the Parties

As the Commission is approving a lesser revenue requirement than sought by PPL, an important consideration is the determination of how the proposed revenue allocation will be affected by the scaleback in rates.

In this proceeding, PPL and the OCA support a proportional scaleback, with no decrease in revenues for classes that do not receive a rate increase. PPL St. 5-R at 4; OCA St. 3 at 42.

I&E proposed applying the first $1,784,000 to lower the revenue requirement for Rate Schedule RTS customers, with any further reductions applied to Rate Schedules RS, GH-2, SL/AL, and on a conditional basis, LP-5. I&E St. 3 at 16-17.

The OSBA recommended a revenue-based scaleback which would allocate any overall rate increase approved by the Commission to each rate class in proportion to the Company's proposed revenues from each class. OSBA St. 1 at 13.

PPLICA supported the scaleback recommendation proposed by the OSBA in the event that the Commission approves an overall revenue increase lower than the Company's requested $104.6 million increase. PPLICA argued that application of a proportional scaleback in this proceeding would hinder progress to cost of service rates by reducing rate increases for customers paying below cost of service rates pursuant to PPL's COSS, but not allowing correlating adjustments for customers whose present rates are above cost of service. PPLICA M.B. at 19, PPLICA R.B. at 9.

PPLICA further asked that should the Commission not adopt the OSBA recommendation, then the scaleback should be applied to all rate classes receiving an increase as proposed by the Company and the OCA, with no further exclusions, as would apply under I&E's proposal. PPLICA opposed the restrictions on the scaleback for Rate Schedule LP-5 that I&E recommended, since that rate schedule is already targeted for a substantial increase. PPLICA M.B. at 18-19.

b. ALJ's Recommendation

The ALJ stated that in the *Lloyd* decision, the Commonwealth Court disapproved the setting of rates according to a flat across-the-board percentage, because there was no dispute that the cost of serving each rate class varied and that rates for certain classes were subsidizing rates for others in the interest of keeping the increase in the total bills of each class to 10% or less. Accordingly, the ALJ found that any scaleback should be utilized to bring the rates of each rate schedule closer to the cost of service. R.D. at 111.

However, the ALJ concluded that this concept, applied blindly, would result in reductions to customers who were not expecting an increase, or greater reductions to some customers than were originally proposed, to the detriment of those whose rates will rise more than necessary. Therefore, the ALJ recommended that PPL's proposal to apply any scaleback on a proportional basis to only those rate schedules that receive increases should be adopted by the Commission. R.D. at 112.

c. Exceptions

In its Exceptions, I&E states that it agrees with the ALJ, but believes the Commission should moderate the increases proposed for the Rate RTS usage rate and the LP-5 customer charge before the proportionate scale-back is applied. I&E Exc. at 29-30.

In its Exceptions, the OCA stated that, as a general principle, it has no disagreement with PPL's proportional scaleback approach. However, the OCA disagrees with using PPL's revenue allocation as a starting point for the proportional scaleback. The OCA submits that its revenue allocation be used as a starting point for a proportional scaleback in this proceeding. OCA Exc. at 34.

The OSBA also excepted to the ALJ's recommendation, stating that the ALJ erred in recommending a proportional scaleback of the rate increase for only those customer classes that were assigned rate increases by PPL. The OSBA avers that Rate Schedule GS-3 is significantly overpaying its cost of service at current rates, and only received mild relief under PPL's original proposed revenue allocation.[18] The OSBA avers that the problem with the proportional scaleback is the progress toward cost-based rates that was part of the original intent of the Company's revenue allocation will not be retained. Under the method adopted by the ALJ, certain customer classes will not benefit from the reduction in PPL's proposed rate increase. The OSBA alleges that the I&E scaleback proposal results in the same unacceptable result. The OSBA recommends that any reduction in the overall increase be shared among the rate classes in proportion to the Company's originally proposed revenues. According to the OSBA, its recommended scaleback methodology maintains the progress towards cost-based rates that was present in PPL's original revenue allocation proposal. OSBA Exc. at 5-12.

[18] The OSBA included Tables showing that the GS-3 class rate of return at present rates is 11.4 percentage points above system average, and, even with the proposed rate decrease, remains 8.2 percentage points above system average at PPL's proposed rates. OSBA Exc. at 8.

Exceptions to the ALJ's recommendation were also filed by PPLICA, wherein it states that the ALJ erred in rejecting the OSBA recommendation of a revenue-based scaleback. PPLICA observes that PPL has now filed four base rate cases since *Lloyd*, without achieving cost-based rates for certain rate schedules. PPLICA avers that it is imperative that any scaleback applied to the lower revenue requirement also reflect continued progress towards cost-based rates. PPLICA opines that despite the ALJ explicitly acknowledging the directives and principles from *Lloyd*, the ALJ inexplicably declined to adopt the revenue-based scaleback proposed by the OSBA. PPLICA echoes the comments of the OSBA that approval of a proportional scaleback would reverse progress towards cost-based rates by reducing rates for customers receiving an increase, but still paying below cost rates. At the same time, rate schedules currently paying above-cost rates, but not receiving an increase, would be excluded from a scaleback, explains PPLICA. According to PPLICA, no reasonable basis exists for approving a scaleback that reverses progress towards cost-based rates. PPLICA Exc. at 3-6.

In reply to the arguments of the OSBA and PPLICA, PPL states that the scaleback method recommended by the ALJ is fair and should be approved. PPL maintains that the ALJ's recommended scaleback is the same method the Company proposed in its 2010 case, which was litigated and adopted by the Commission. PPL avers that both the scaleback recommended by the ALJ and the method proposed by the OSBA would move rate classes towards the system average return. However, PPL opines that as a matter of fairness, any scaleback of revenues should be applied to those customer classes that would have received a rate increase under the Company's original proposal. PPL R.Exc. at 17.

In its Replies to Exceptions, the OCA states that the ALJ was correct in recommending the use of a proportional scaleback. The OCA notes that the OSBA recommendation was directly addressed in PPL's 2010 case and rejected by the ALJ and the Commission, which stated that asking one class to pay more of an increase than the final total increase in revenue would be unreasonable. According to the OCA, the OSBA's proposed scaleback methodology would impose additional costs on certain rate classes, over and above the total revenue increase authorized, in order to provide additional rate decreases to other rate classes. The OCA avers that neither the OSBA nor PPLICA provide evidence to support the idea of what constituted unreasonable rates in 2010 is now acceptable. OCA R.Exc. at 15-17.

In its Replies to Exceptions, PPLICA first states that since the OCA's proposed revenue allocation is *per se* unreasonable, any scaleback based upon it should be disregarded by the Commission. Additionally, PPLICA avers that an increase-based scaleback will significantly hinder progress towards cost-based rates. PPLICA requests that the Commission deny any proposal to apply a proportional increase-based scaleback and adopt the revenue-based scaleback proposed by the OSBA. PPLICA R.Exc. at 10-11.

d. Disposition

Based upon our review of the record evidence, we are in agreement with the recommendation of the ALJ that PPL's proposed proportional scaleback only to those classes that were proposed to receive rate increases, of the requested revenue increase, are fair, reasonable and should be approved. We find that the OCA's Exceptions with regard to the proper starting point are without merit, as we have herein previously rejected the OCA recommended allocation proposals. We further conclude that the I&E's Exceptions with regard to first providing relief to certain designated rate classes before the proportional scaleback is applied are also without merit.

The OSBA, as well as PPLICA, filed Exceptions opposed to the adoption of a proportional scaleback. These Parties are of the opinion that a revenue based scaleback should be adopted and applied to all customer classes, whether they were to originally receive no increase or a rate decrease. On this point, we are persuaded by the comments of PPL that the ALJ's recommended scaleback is the same method the Company proposed in its 2010 case, which was litigated and adopted by the Commission. Neither the OSBA nor PPLICA have presented sufficient evidence to warrant our reconsideration of this issue in this proceeding. We find that, as a matter of fairness, those customer classes that have not been allotted any rate increase via the Company's original revenue allocation should not receive rate decreases as argued by the OSBA and PPLICA. We conclude that PPL's proposed scaleback methodology maintains the gradual movement to cost based rates and is appropriate under the unique circumstances in this proceeding. Accordingly, the Exceptions of I&E, the OCA, the OSBA and PPLICA are denied, and the ALJ's recommendation is adopted.

4. Residential Customer Charge

a. Positions of the Parties

PPL's current residential distribution schedules are RS, RTS, and Residential Time-of-Day (RTD). In PPL's presently effective residential Rate Schedule RS, a large portion of the distribution revenue is being collected through usage or kWh charges. PPL's minimum size system study indicated that residential customers should be paying a much greater monthly customer charge than the current monthly charge of $8.75. In this proceeding, PPL has proposed raising the Rate Schedule RS customer charge from its present $8.75 per month to $16.00 per month and decreasing the kWh charges from $0.03364 to $0.03340. PPL St. 5 at 11-14. The Company pointed out that its COSS supports a charge of $36.70, and this increase moves the rate schedule closer to the cost of serving it. PPL M.B. at 162-163.

The OCA, the CEO and I&E opposed PPL's proposal to increase the Rate Schedule RS customer charge.

The OCA opposed the increase to residential customers because it is based on the Company's COSS, which it also opposed. The OCA objected further that the Company's proposal will disproportionally impact low-income, low-usage customers and would result in a "significant disincentive" for customers to conserve. OCA M.B. at 106.

The CEO opposed the increase in the fixed monthly customer charge because it takes away a customer's motive and ability to conserve. The CEO stated that one of the only defenses that a family has against sharp increases in energy costs is conservation, CEO St. 1 at 5, and this proposal eliminates the ability to reduce that cost through conservation efforts. CEO M.B. at 7.

The Company pointed out that there is an energy charge component that is being reduced by 0.7%, and that the distribution charge is small in the context of the energy portion of the bill, which comprises 86% of the charges on the average customer's bill. According to PPL, this still provides an adequate opportunity for savings due to conservation. PPL St. 5-R at 6; Exh. DAK4; PPL M.B. at 164.

I&E developed its own offering based upon a direct customer analysis. In preparing its direct customer cost analysis, I&E stated that it was guided by long-standing Commission precedent that identifies the appropriate items to be included in a customer charge. According to I&E, those items that change with the addition or loss of a customer are the direct customer costs that were identified in the Company's cost of service study and are as follows: meter expenses, expenses for services and customer installations, expenses for meter reading and customer records & collection, other customer accounting expenses, depreciation expense and net salvage amortized for meters and services, and the rate base related return and income taxes on customer-based rate base. I&E maintained that the Commission has long held these costs to be those most appropriately included in a customer cost study. I&E M.B. at 131 (citing *Pa. PUC* *v. West Penn Power Company*, 59 Pa. P.U.C. 552 (1985)). I&E noted that recently the Commission accepted a direct customer cost analysis identical to the analysis it presented in this proceeding[19] in the Columbia Gas of Pennsylvania base rate case at Docket No. R-2010-2251623 (Order entered October 14, 2011). I&E recommended that the RS customer charge remain unchanged at $8.75 per month. I&E M.B. at 130-133.

The Company countered that the OCA and I&E alternative customer cost analyses include only meters and services and exclude all other customer costs, which should be included in a customer charge. PPL M.B. at 170. Further, PPL pointed out that "conservation cannot and does not trump cost of service." PPL M.B. at 164.

However, in response to the positions of the other Parties, PPL proposed an alternative plan that includes a residential customer charge of $14.09 per month, consistent with the recent Commission decision in *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket No. R-00038805 (Order entered August 5, 2004) (*Aqua*). PPL stated that the costs included in its alternative Rate Schedule RS customer charge of $14.09 per month properly reflect meters and services net plant and related O&M expenses; meter reading and billing and collection expenses, and the Company's Meter Data Management System; as well as related employee benefits, administrative and general expenses and other O&M expenses related to the above items. These revenue requirement cost components represent the same type of direct and indirect cost components as those approved in *Aqua*. PPL M.B. at 172. The only difference is that PPL also included $12,678,000 for customer call center-related expense. PPL averred that this expense was not specifically addressed in *Aqua*, but it is consistent with the expenses included in the customer charge in *Aqua,* because it is a directly assignable customer service-related expense, and it varies with the number of customer calls and the number of customers. *Id*. at 173; PPL St. 8-RJ (Part 2) at 8.

---

[19] Tr. at 541-42.

While PPL opined that the customer component of each rate schedule should include all customer-related costs determined by the cost of service study, if the Commission wished to consider an alternative compromise customer charge, PPL posits that its alternative proposal of $14.09 would be acceptable as it would recover the same type of direct and indirect cost components as those approved in *Aqua*, and would provide some improvement in the level of fixed cost recovery in the customer charge. PPL St. 5-R at 15; PPL M.B. at 172-173.

I&E responded that it is improper to offer a compromise outside the context of a settlement, and that without an actual settlement the Company's position still needs to rely on substantial evidence to support it, which it did not provide. I&E R.B. at 107.

b. ALJ's Recommendation

The ALJ stated that while it would be improper to propose a compromise position for the first time in a brief or exception, it is not improper to propose an alternative during the litigation, when the supporting data already appears in the record, as PPL did in this proceeding. The ALJ recommended approval of the PPL alternative as it is based on an approved cost of service study, which clearly illustrates that customer-related costs for the residential class include elements that I&E ignored in its own analysis and determination of a proper residential customer charge. The ALJ found that it is reasonable to include some of these additional elements in calculating the residential customer charge, as the Commission allowed in the *Aqua* case. R.D. at 120.

According to the ALJ, the Company will be ensured recovery of more of its fixed costs, which are clearly more customer-related than usage-related, while still allowing some revenue to be recovered through usage-based charges. Thus, customers will be provided with more accurate price signals, while still being afforded some opportunity to control their monthly distribution bills through conservation. For these reasons, the ALJ concluded it is appropriate and reasonable to accept PPL's compromise position regarding the residential customer charge. R.D. at 120.

c. Exceptions

In its Exceptions, I&E states that the ALJ's recommendation to adopt the Company's compromise lacks legal support. I&E avers that as originally proposed, PPL's entire residential increase was to be recovered from an 82% increase to its RS customer charge without providing any direct customer cost analysis. I&E notes that PPL provided only a COSS, which is an entirely different cost analysis. According to I&E, PPL found very few, if any, distribution system-related costs that were a function of usage and proposed to recover essentially all fixed costs in the customer charge. I&E states that PPL included all fixed costs that it classified as customer related, as opposed to demand related, in the customer charge and made no distinction between direct and indirect costs. I&E avers that fixed costs and customer costs are not synonymous and opines that fixed costs assigned to the customer charge should be limited to those fixed costs for which there is a direct impact from an individual customer, such as metering and billing. I&E Exc. at 30-31.

Next, I&E notes that although PPL moderated its Rate RS proposal in rebuttal, it still failed to conduct an appropriate customer cost analysis. Rather, I&E asserts that PPL presented a "study" that included both direct and indirect costs that it claimed authorized a $36.70 RS customer charge, but under which PPL only claimed a "compromise" RS customer charge of $14.09.[20] I&E avers that the ALJ's reliance on one aberrant Commission order from 2004, *Aqua,* to support her recommendation to

[20] I&E asserted that PPL produced no such "study" and made no such "compromise" offer with respect to its originally proposed non-residential customer charges. I&E Exc. at 32.

adopt the PPL compromise position lacks adequate legal support. I&E opines that the *Aqua* case is not controlling as the holding of that case, with respect to the inclusion of indirect costs in the calculation of a customer charge, has not been reaffirmed or reapplied since 2004. I&E maintains that since 1985 and most recently in 2011, with the one exception being *Aqua*, the Commission affirmed the basic customer cost analysis it originally articulated in 1985. I&E Exc. at 31-33.

Lastly, I&E states that as *Aqua* formed the sole basis presented by the ALJ for adoption of the Rate RS customer charge, the ALJ's recommendation should be rejected. I&E maintains that PPL's "compromise" RS customer charge fails to meet the parameters of a properly constructed customer cost analysis. Additionally, I&E asserts that the ALJ's recommendation is not supported by the overwhelming Commission precedent and, unless prepared to enunciate a new standard, the Commission should reject it. Further, I&E notes that customers will lose control over a substantial part of their bill, very likely deterring conservation efforts despite the millions of dollars customers have invested in energy conservation efforts. I&E Exc. at 35-36.

The OCA also excepts to the ALJ's recommendation, arguing that PPL's proposed customer charge is based on its flawed COSS results, does not represent the results of a direct customer cost analysis, would disproportionately impact low-income, low-usage customers and would result in a significant disincentive for customers to engage in conservation activities. The OCA recommends that the Rate RS customer charge continue to be set at its correct level of $8.75. The OCA avers that the ALJ erred by accepting PPL's alternative RS customer charge without a direct cost study as support for such a charge. According to the OCA, the Commission has repeatedly expressed its preference for a direct cost study, which includes only direct costs and not indirect costs, as PPL has done in its alternative proposal as a basis to set customer charges. The OCA notes that, in contrast to the decades of Commission precedent on this issue, PPL supports its alternative customer charge with the lone case of *Aqua*. The OCA submits that the *Aqua* decision was fact specific and provides no support for PPL's current proposal. OCA Exc. at 34-36.

Next, the OCA explains that it performed a direct customer cost analysis, consistent with Commission precedent, and found that the direct residential customer costs ranged from $7.70 per month to $8.24 per month. Therefore, the OCA is of the opinion that the current RS customer charge of $8.75 is reasonable and should not be increased. The OCA avers that PPL's proposed customer charge will disproportionately impose adverse impacts on the customers least able to afford those bill increases and should not be accepted. OCA Exc. at 36-37.

In its Replies to Exceptions, PPL states that unlike the case relied upon by I&E, nothing in *Aqua* limits the Commission's holding only to that case. PPL avers that the Commission clearly stated that requests to include allocated indirect costs, such as employee benefits, local and payroll taxes, and other general and administrative costs, should be reviewed on a case-by-case basis, citing *Aqua,* at 70-72. PPL further submits that there is no order from either the Commission or the appellate courts overturning or otherwise limiting the Commission's conclusion in *Aqua*. PPL maintains that it followed the Commission's conclusion in *Aqua* and proposed the inclusion of the same type of direct and indirect cost components approved by the Commission in *Aqua*. PPL continues that I&E and the OCA failed to offer any criticisms or reasons to exclude from the customer cost study and customer charge the indirect costs that PPL allocated for employee benefits, local and payroll taxes, and other general and administrative costs. For these reasons, PPL opines that the ALJ properly rejected the positions of I&E and the OCA. PPL R.Exc. at 17-18.

With regard to the Parties' comments on the impact on low income/low usage customers, PPL agrees that increasing the monthly charge while essentially maintaining the usage charge at its current level will result in a greater than average percentage increase to low use customers, regardless of their income level. However, PPL avers that as a utility with an obligation to serve, it must provide infrastructure to serve the needs of those customers. PPL states that utility rates should be designed based upon cost of service, not customers' income levels. According to PPL, ability to pay issues should be addressed through USPs, not by setting rates that disregard the cost of service. PPL R.Exc. at 19.

d. Disposition

Upon our consideration of the evidence of record herein, we shall adopt the ALJ's Recommendation on this issue that PPL's compromise proposal is reasonable and should be approved. In this regard, we conclude that PPL's original proposal is excessive, disregards the principle of gradualism and is not reasonable. Additionally, we conclude that the recommendations of I&E and the OCA that the residential customer charge not be increased at all in this proceeding are equally unreasonable as they are not based on a proper cost analysis. We further conclude that the ALJ correctly recommended that, consistent with *Aqua,* other customer-related costs are properly includable in a customer charge cost analysis. We find that the I&E proposed limitation of costs to only services and meters excludes all other customer costs that should be included in a customer charge and is unreasonably narrow.

With regard to the concerns expressed by the opposing Parties that PPL's compromise proposal discourages conservation, we note our agreement with the Company's observation that the distribution charge is relatively small in the context of the energy portion of a customer's bill, which comprises approximately 86% of the charges on the average customer's bill. Therefore, we find that this will provide a more than adequate opportunity for customer savings due to energy conservation.

Therefore, we find that PPL has met its statutory burden of establishing the reasonableness of its compromise proposal. Accordingly, we adopt the recommendation of the ALJ and deny the Exceptions of I&E and the OCA on this issue.

5. Non-Residential Customer Charges

a. Positions of the Parties

PPL proposed increases to the customer charges in the Small General Service -- Rate Schedule GS-1 (GS-1), Large General Service – Rate Schedule GS-3 (GS-3), Large Power Firm Service at 12 kV – Rate Schedule LP-4 (LP-4), and Large Power Service at 69 kV – Rate Schedules LP-5, LP-6, and IS-T (LP-5,LP-6 and IS-T).

PPL proposed to increase the customer charge for Rate GS-1from $14.00 to $16.00 per month and decrease the demand charge from $4.530 to $4.258 per kW. PPL stated it has installed demand meters on all GS-1 customer premises, except for small unmetered constant load accounts. PPL St. 5 at 15; PPL Exhs. DAK 1, DAK 2; PPL Exh. 1, Exhibits Regs.

PPL proposed to increase the customer charge for Rate GS-3 from $30.00 to $40.00 per month and decrease the demand charge from $4.510 to $4.192 per kW. PPL St. 5 at 15; PPL Exhs. DAK 1, DAK 2; PPL Exh. 1, Exhibits Regs.

PPL proposed to increase the customer charge for Rate LP-4 from $160.19 to $170.00 per month and decrease the demand charge from $2.136 to $2.127 per kW. PPL St. 5 at 16; PPL Exhs. DAK 1, DAK 2; PPL Ex. 1, Exhibits Regs.

PPL proposed to increase the customer charge for Rate Schedule LP-5 from $709.00 to $1,125.00 per month. PPL stated that presently, there are only two customers on Rate Schedule LP-6. As there is no difference between Rate Schedules LP-6 and

LP-5, PPL proposed to eliminate LP-6 and move the two remaining customers to Rate Schedule LP-5. Finally, PPL proposed to eliminate Rate Schedule IS-T because there are no customers on this interruptible service program. According to PPL, all of its interruptible service programs have been superseded by PJM Interconnection LLC's (PJM) programs. PPL St. 5 at 17; PPL Exhs. DAK 1, DAK 2; PPL Exh. 1, Exhibits Regs. PPL M.B. at 157-162.

According to PPL, its proposals to increase the customer charges and reduce the demand charge for these rate schedules are consistent with *Lloyd*, which held that rate structures should be adjusted to reflect the cost of service to each rate class and to eliminate cross-subsidization. *Id.*

I&E argued that the customer charges for these rate schedules should not be increased. I&E used its own direct customer cost analysis which, the Company argued, excludes certain items that the Company evaluation includes. I&E St. 3 at 12-14.

The Company averred that its minimum size system study is the appropriate basis for determining the fixed customer costs that are incurred to serve customers, and that those fixed costs should be recovered through a fixed customer charge. PPL argued that I&E's approach to setting the fixed monthly customer charges ignores the customer costs of the fixed and permanent infrastructure that the electric distribution company is obligated to provide and which exists between a customer's service and the transmission substation from which the customer's load is served. PPL M.B. at 174.

b. ALJ's Recommendation

The ALJ stated that as she accepted the Company's cost of service-based evaluation for residential customers, it was consistent to accept it for the commercial and industrial customers as well. Therefore, the ALJ recommended that PPL's proposals be approved. R.D. at 121.

c. Exceptions

In its Exceptions, I&E states that the ALJ's recommendation to adopt the Company's non-residential customer charges to be consistent with the recommendation regarding the residential customer charge lacks factual support. I&E avers that its customer cost analysis did not distinguish between residential and non-residential classes, but was guided solely by the results of the properly constructed direct customer cost analysis. I&E points out that, while PPL proposed an alternative customer charge for the residential class, the Company produced no study or compromise offer with respect to its originally proposed non-residential customer charges. I&E asserts that the ALJ's recommendation to adopt PPL's non-residential customer charges to be consistent with the residential class is actually inconsistent since PPL did not present a compromise analysis applicable to the non-residential customer charges. Therefore, I&E opines that on the basis of that error, the ALJ's non-residential recommendation should not be adopted. I&E Exc. at 30-36.

In reply, PPL acknowledges that it has the burden of proof to establish that its proposed non-residential customer charges are just and reasonable; however, it is not required to develop and present alternatives that it does not support. PPL avers that the evidence demonstrated that I&E's non-residential customer charges are based on its own direct customer cost analysis, which is based on a flawed process. PPL R.Exc. at 19-20.

d. Disposition

Upon our consideration of the record evidence, we conclude that PPL's proposed non-residential customer charges are reasonable and should be approved.

While the ALJ's comment concerning consistency may not be entirely accurate[21], we find that her recommendation to approve PPL's non-residential customer charges is correct. It is important to note that none of the other Parties directly affected by these increased customer charges were opposed to the increase. Only I&E filed Exceptions to the ALJ's recommendation based on its own customer charge cost analysis that we have previously rejected. Accordingly, finding the ALJ's recommendation to be otherwise reasonable and duly supported by the evidence of record herein, it is adopted. The Exceptions of I&E on this issue are denied.

6. Net Metering for Renewable Customer-Generators Rider

a. Positions of the Parties

PPL proposed two changes to its Net Metering tariff provisions for Renewable Customer-Generators. First, PPL proposed to establish a limitation on the size of generator relative to the associated customer usage that would be eligible for net metering. Second, PPL proposed to clarify that, for eligible customer-generators served under PPL's Time of Use default service rate option, a weighted average of the on-peak and off-peak hour prices would be used to derive the Price to Compare for the purpose of compensating customer-generators for excess generation. PPL St. 5 at 25; PPL Exh. DAK 2; PPL M.B. at 180-181.

Both SEF and Granger opposed PPL's proposal to limit the eligibility for net metering based on the size of the generator relative to the associated customer usage. Granger opposed the as-filed proposal, as the Company proposed to limit the generation in all new net-metering applications to 110% of the customer-generator's connected load.

---

[21] The ALJ stated that as she accepted the Company's cost of service-based evaluation for residential customers, it was consistent to accept it for the commercial and industrial customers as well. However, we note that PPL did not present a compromise analysis for the non-residential customer charge as it did for the residential customer charge.

SEF pointed out that the Company had provided no evidence to support an allegation that net metering customers cause PPL to incur costs that support an increase in the customer charge and asked that this allegation be rejected. Granger M.B. at 9, SEF R.B. at 1-2.

In response to this opposition, PPL withdrew this proposal and instead proposed a tariff revision to comply with the wording from the policy adopted by the Commission in the Commission's Final Order entered March 29, 2012, at Docket No. M-2011-2249441.[22] This revision limits the 110% restriction to the business model where a third-party developer builds, owns, operates and maintains an alternative energy generation system on or near a customer's property and sells power and/or alternative energy credits to that customer. PPL St. 5-R.

Granger stated that the Company's revised proposal incorporated language from that Commission Order, and, consequently, it did not oppose the proposal. Granger M.B. at 9.

No party opposed PPL's second proposal, which was to revise the tariff to use the weighted average of the on-peak and off-peak hour TOU prices to derive the Price to Compare for customers served under PPL's Time of Use default service rate option. PPL explained that the stated purpose of this proposal was to ensure that compensation for excess generation by TOU customer-generators more closely reflects their actual on-peak and off-peak usage and generation. PPL M.B. at 180-182.

b. ALJ's Recommendation

The ALJ recommended that the revised net metering proposals be approved. R.D. at 126.

---

[22] *Net Metering – Use of Third Party Operators*, Docket No. M-2011-2249441 (Order entered March 29, 2012).

c. Disposition

No Party filed exceptions to the ALJ's recommendation. Finding it to be reasonable, we adopt it without further comment.

7. Competitive Enhancement Rider (CER)

a. Positions of the Parties

The Company proposed a new rider, the CER, to recover the costs of all customer education programs. PPL will estimate the total costs it expects to incur, on a calendar-year basis, to provide consumer education programs and competitive retail electricity market enhancement initiatives for all customers who receive distribution service from PPL. According to PPL, the CER will be a Section 1307(e), 66 Pa. C.S. § 1307(e), cost recovery mechanism developed to recover the Company's education and retail market enhancement (RME) related costs. PPL St. 8 at 30-32; PPL Exh. DAK 2; PPL M.B. at 180.

PPL argued that the Commission and the appellate courts have held that an automatic adjustment clause is appropriate when the expenses to be recovered are substantial, subject to variation and beyond the control of the utility. PPL M.B. at 206 (citing *Popowsky v. Pa. PUC,* 869 A.2d 1144, 1159 (Pa. Cmwlth. 2005); *Pennsylvania Industrial Energy Coalition v. Pa. PUC,* 653 A.2d 1336 (Pa. Cmwlth. 1995); *Pa. PUC v. Newtown Artesian Water Co.,* Docket No. R-2009-2117550 (Order entered April 15, 2010); *Pa. PUC v. Philadelphia Thermal Energy Corp.,* 1991 Pa. PUC Lexis 80). According to PPL, its competitive enhancement expenses meet each of these standards. PPL M.B. at 206.

The Company estimated that the costs of the mandates in the RMI and other proceedings will be more than $6 million annually, at least at the beginning, but will depend on the Commission's direction and are not within the control of the Company. PPL M.B. at 206.

The OCA, the OSBA, and Direct Energy have raised various issues and concerns regarding the proposed CER.

The OCA cautioned that care must be taken to prevent double recovery of these costs. In addition, the OCA noted that the Commission had recently held that the competitive enhancement costs should not be collected from ratepayers but from the EGSs. OCA M.B. at 125 (citing *Petition of FirstEnergy,* Docket No. P-2011-2273650, at 136 (Order entered August 16, 2012). The OCA recommended three safeguards: (1) that the allowed costs must conform to the standards in the Commission's May 10, 2007 Order at Docket No M-000061957; (2) that competitive enhancements costs incurred by PPL, consistent with the Commission's directive, be collected from EGSs; and (3) that there be quantifiable assurances in place to prevent double recovery of these costs, such as through the CER and within the approved revenue requirement in this case. *Id.* at 125-126.

The OCA also recommended that the costs be allocated on a per kWh basis instead of per customer, reasoning that those with higher usage will benefit more from the information. According to the OCA, costs are incurred on a per customer basis and should be allocated accordingly. OCA M.B. at 126.

REG avers that Rate CER should be applied only to those customers and customer classes that benefit from the programs, activities, and enhancements funded by Rate CER. As customers already shopping know that they can shop and that Rate CER provides an incentive to customers to shop to the extent that it is imposed on them, Rate

CER is best imposed on non-shopping customers to provide them with an incentive to shop and should not be imposed upon customers who have already selected alternative suppliers. REG M.B. at 6; REG R.B. at 1.

PPLICA limited its argument to cautioning the Commission to ensure that the Company's costs are not duplicated in multiple education programs. PPLICA M.B. at 21. PPLICA noted further that the Company's proposal to recover costs of RME programs from the EGSs that benefit from them is consistent with the Commission's Final Order in *Investigation of Pennsylvania's Retail Electricity Market: Intermediate Work Plan,* Docket No. I-2011-2237952 (Order entered March 2, 2012) and, therefore, PPLICA supported this proposal. PPLICA M.B. at 21.

Regarding recovery of costs, PPLICA opined that the costs allocated to a customer class should be recovered per customer, not per kWh, as proposed by the OCA as this is contrary to cost causation principles. PPLICA did not oppose approval of the proposal to recover CER costs through a fixed monthly customer charge. PPLICA M.B. at 23.

PPL asserted that to the extent it recovers these costs from EGSs, they would not be recovered through the CER. PPL M.B. at 209.

b. ALJ's Recommendation

The ALJ recommended that the CER be approved, and that the costs incurred by the Company in implementing the RME programs, including consumer education costs not recoverable from the EGSs, be recovered using the CER. The ALJ further recommended that as all customers benefit from the robust competitive market, then all customers should bear the costs involved in its development, on a per customer basis. R.D. at 128.

c. Exceptions

In its Exceptions, the OCA states that it opposes the ALJ's recommendation regarding retail market enhancement programs, and submits that this type of cost recovery for RME programs is inconsistent with the Commission's directives in this area. The OCA cites to the Commission's recent decision wherein the Commission held that EGSs should pay for RME costs. *Petition of FirstEnergy*, Docket No. P-2011-2273650, at 136 (Order entered August 16, 2012). The OCA avers that *FirstEnergy* is consistent with the Commission's decision to require EGSs to pay for the costs of opt-in auction programs in *Investigation of Pennsylvania's Retail Electricity Market: Intermediate Work Plan, supra,* at 79. OCA Exc. at 37-38.

The OCA also states that consumers that use more energy clearly have greater potential to benefit from these customer education programs than consumers who use very little electricity. Therefore, the OCA opines that a per kWh based rider better equates the costs and benefits of these programs. The OCA submits that whatever consumer education costs are ultimately recovered from ratepayers should be done on a kWh basis. OCA Exc. at 38-39.

The OSBA also excepted to the ALJ's recommendation, stating that there is no need at this time for yet another PPL reconcilable charge. The OSBA avers that implementing another rider will simply lead to the need for enhanced regulatory oversight to ensure that the costs claimed under the new rider include only those costs that were specifically identified as being associated with that rider. The OSBA notes that it agrees with PPL that it should be allowed to fully recover these costs, that many of these costs should be recovered from EGSs and that other Pennsylvania EDCs have similar riders. However, the OSBA does not believe that these costs should be recovered in the context of the instant distribution rate proceeding. The OSBA opines that a rate rider designed to recover RME costs would be better addressed in the Company's pending default service proceeding at Docket No. P-2012-2302074. According to the OSBA, it is established Commission policy that RME costs should be borne by EGSs and that this issue should be resolved in default service proceedings. OSBA Exc. at 15 (citing *FirstEnergy, supra,* at 136). OSBA Exc. at 13-15.

Next, the OSBA maintains that if the Commission does decide that the CER is necessary, then PPL's rate design for recovering the costs of the CER program should be changed. Instead of recovering these costs equally across all of the Company's customers as recommended by the ALJ, the OSBA submits that these costs should be directly assigned to PPL's rate classes for which costs can clearly be attributed. Furthermore, the OSBA avers that costs not specifically associated with a rate class should be allocated using some reasonable cost-based allocation factor. Then the Company should develop a separate CER charge for each rate class or rate class group, based on the allocated costs. OSBA Exc. at 16-17.

Finally, the OSBA submits that it is much more reasonable to directly assign costs, where possible, so that the cost-causing customer class pays. The OSBA asserts that in light of the high level of shopping that already exists among PPL's non-residential customers, it is not clear that there is any benefit to be gained by developing RME programs for these customers. Additionally, if RME programs apply only to the residential class, PPL's proposal to effectively allocate those costs among all customers is clearly at odds with both cost causation and fairness considerations. OSBA Exc. 17.

In reply, PPL states that its proposed CER is appropriate for three principal reasons. First, PPL avers that such automatic adjustment clauses are appropriate for expenses that are substantial, vary and are beyond the utility's control. According to PPL, initially the CER annual expenses will total more than $6.0 million and, thus, are substantial. PPL opines that they are subject to variation because they will change depending on Commission mandates in the RMI and other proceedings, and they are beyond PPL's control as they are incurred under Commission directives. Second, PPL avers that a CER permits a more flexible approach because it can be adjusted annually should the need for spending levels change in the future. PPL notes that such flexibility is not available if these costs are recovered through base rates. Third, PPL avers that other EDCs are employing Commission approved rider mechanisms to recover expenses incurred in response to the RMI. PPL R.Exc. at 23.

In response to the concerns expressed regarding the double recovery of costs, PPL maintains that the use of a specific reconcilable rider for all customer education expenses would assure that all costs are recovered only once. PPL opines that the possibility of double recovery would be eliminated as these expenses would all be reviewed annually in one reconciliation proceeding, and these expenses and revenues would be trued-up annually to make sure that only actual expenses are recovered. PPL R. Exc. at 23-24.

In response to the rate design issue expressed by the Parties, PPL avers that customer education costs should be recovered as it proposes on a per customer basis. PPL submits that this is consistent with cost causation because it costs the same to send a notice to an industrial customer as to a residential customer. PPL R.Exc. at 24.

Finally, PPL notes that the OSBA's proposal that the CER be addressed in PPL's default service proceeding is impractical, as it is too late for such matters to be considered in that proceeding since the record is closed. Also, PPL submits that it is important for PPL's proposed CER to be considered in this base rate case because, if it is adopted, it will have a direct impact on the level of base rates charged to customers. If it is not adopted, PPL claims that these costs would have to be recovered through base rates. PPL R.Exc. at 24.

In its Replies to Exceptions, PPLICA states that the ALJ correctly approved recovery of the costs included within the CER on a per customer basis. PPLICA avers that the costs potentially recoverable through the CER are generally customer costs and therefore rightfully recovered on a per customer basis. According to PPLICA, potential CER costs comprise broad marketing and education programs, which are readily distinguishable from the more consumption or demand-oriented energy efficiency and conservation plans administered under Act 129 of 2008. PPLICA R.Exc. at 11.

d. Disposition

We are in agreement with the ALJ that PPL's proposed CER is appropriate and should be approved. The CER is meant to recover the costs incurred by PPL to implement the RME Programs, including consumer education costs, not recoverable from EGSs, and should be designed on a per customer basis as proposed by PPL. We are persuaded by the arguments in favor of the CER presented by the Company. We agree that the costs proposed to be recovered through the CER qualify for recovery under an automatic adjustment clause, consistent with the Commonwealth Court's reasoning in *Pennsylvania Industrial Energy Coalition v. Pa. PUC,* 653 A.2d at 1349. We also concur that the CER provides a more flexible methodology for the Company to recover these Commission mandated expenses, and the CER is consistent with Commission approved recovery mechanisms we have adopted in other EDC proceedings. Furthermore, we agree with PPL that these costs are properly recoverable on a per customer basis, consistent with cost-causation principles. Accordingly, we shall adopt the recommendation of the ALJ and deny the Exceptions of the OCA and the OSBA on this issue.

8. Purchase of Receivables

a. Positions of the Parties

PPL purchases, at a discount, the accounts receivable of EGS customers who participate in the Purchase of Receivables (POR) program. This discount is composed of an uncollectible accounts percentage factor and a development, implementation, and administrative factor. Uncollectible expenses are those costs that result from customers not paying for service, and the amount of the non-payment is written off. Uncollectible accounts expense associated with generation supply and transmission service for default service customers is separated from the Company's distribution rates and recovered through the Merchant Function Charge (MFC) and included in its Price to Compare. The cost of uncollectible expense is recovered from default customers through the MFC and from shopping customers through the discounted rate at which PPL purchases the accounts receivable within the POR program. PPL M.B. at 184-185.

The MFC percentages for the residential and small C&I customer classes have been calculated on the Company's expected 2012 uncollectible accounts expense for those customer classes. Based thereon, PPL proposed to change the MFC for the residential class from 1.80% to 2.23% and for small C&I customers from 0.10% to 0.23%. PPL St. 8 at 29-30; PPL St. 8-R at 43-44; PPL Exh. JMK 4.

PPL stated that in the ordinary course of business, the entity rendering the service is responsible for the costs and actions associated with billing and collection of payments, and also bears the risk of non-payment or late payments. Under a POR program, the EGS sells its accounts receivable to PPL and receives immediate payment for the amount due minus a discount meant to reflect collection risk and the time value of money. A POR program, therefore, allows the seller of the receivables to receive payment sooner and avoid the costs and risks associated with collecting any delinquent amounts owed by the customer. PPL M.B. at 184.

PPL explained that the existing POR program was authorized by the Commission's Order in *Petition of PPL Utilities Corporation Requesting Approval of a Voluntary Purchase of Accounts Receivables Program and Merchant Function Charge*, Docket No. P-2009-2129502 (Order entered November 19, 2009). In that Order, the Commission approved a settlement of the following factors: (1) the discount rate for residential service was 1.37%, consisting of an uncollectible accounts expense percentage factor of 1.32% and a POR administrative factor of .05%; (2) in order to participate, an EGS would sell all of its residential customer accounts receivables to the Company; (3) participating EGSs agreed to not reject new customers based on credit-related issues and would not require a deposit; (4) budget billing would be available to customers of participating EGSs; and (5) for small commercial and industrial shopping customers, the discount rate was 0.17%, reflecting an uncollectible accounts expense percentage factor of 0.12% and a POR administrative factor of 0.05%. PPL stated that the percentages were increased in the 2010 base rate case, *Pa. PUC v. PPL Electric Utilities Corporation,* Docket No. R-2010-2161694 (Order entered December 21, 2010). *Id.* at 185.

The Company noted that, in this proceeding, it based its proposed numbers on its actual write-offs from 2011, which were approximately $40 million. PPL M.B. at 187; PPL St. 8-R at 43. To calculate the amount sought, PPL used its proposed 2012 budget amount, which is the sum of projected write-offs and the projected change in the reserve for doubtful accounts for 2012. PPL M.B. at 187; PPL St. 8-R at 44.

Direct Energy and DR opposed PPL's expected 2012 uncollectible accounts expense. Direct Energy recommended, instead, that PPL be permitted to recover 100% of its uncollectible accounts expense by implementing a non-bypassable/non-reconcilable charge applicable to all customers. In the alternative, Direct Energy recommended modifying the Company's proposal in the following manner: (1) by reducing the discount rate to reflect the amount of late payment charges that the Company collects and which offset its net uncollectible accounts expense; and (2) by reducing the discount factor by an administrative cost credit to return to the EGSs the amounts that have been collected through the administrative cost adder but which the Company did not track. Direct Energy St. 1 at 9-11; Direct Energy M.B. at 9.

Direct Energy averred that the Company's proposal must be rejected because there is no record basis to support allocation of the proposed uncollectible accounts expense percentage to generation service customers. Direct Energy claimed that while PPL has proposed that shopping and default customers pay at the same percentage level, it has not provided evidence to support a finding that this is just and reasonable. In fact, the Company admitted that it did not track write-offs by the shopping/default categories. Direct Energy M.B. at 12; Tr. at 404. While Direct Energy pointed out that it is possible that one category may be more reliable in paying bills than the other, and that the shoppers may be unfairly charged here, it is just as likely that the default customers are effectively subsidizing shopping customers. Direct Energy M.B. at 1.

Direct Energy also stated that the Company's proposal will stall development of a fully robust competitive retail market. Direct Energy noted that "[t]he level of competition in PPL's service territory is good, but it could be much better. The current levels of shopping need not only be sustained but increased in order to meet the Commonwealth's goal of a fully competitive retail electric market. PPL's service territory presents the best opportunity to do that, but only if the Commission continues to remain vigilant about properly allocating costs to EGSs." *Id.* at 14 (footnotes omitted).

According to Direct Energy, the levels of uncollectible discount that PPL is proposing to charge through the POR program will have a significant negative effect on the development of competition because EGSs cannot administer their own programs efficiently and inexpensively and have no real choice but to rely on the Company. *Id.* at 15.

PPL denied that this increase will have a negative effect on the competitive market. While Direct Energy and DR argued that the EGSs would have to bear the difference in cost until the expiration of existing fixed-price contracts, PPL pointed out that there should have been no reasonable expectation that the discount rate would remain static indefinitely. According to PPL, such risk was willingly undertaken by the EGSs, is a business risk, and cannot be used to shift the risk of doing business as an EGS to PPL and its customers. PPL R.B. at 105-106.

Direct Energy stated that the Company's failure to properly support its own proposal opens the door for the Commission to consider the Direct Energy alternative, which is to collect total projected uncollectible accounts expense through a non-bypassable charge for all distribution customers. According to Direct Energy, this eliminates the need for determining the actual uncollectible expense. Direct Energy opined that this approach is superior to the Company's because it is consistent across shopping lines and does not contain the possibility of shoppers subsidizing default customers. Direct Energy M.B. at 18.

PPL argued that the dual MFC/POR method appropriately unbundles the uncollectibles charge and properly assigns risk of nonpayment and that Direct Energy's proposal to refund all amounts that PPL has received under the administrative component of the POR should be rejected as impermissible retroactive ratemaking. PPL M.B. at 189-193. PPL also argued that the Commission has no authority to direct a change in its POR program due to its voluntary nature. *Id.* at 185.

Direct Energy responded that the POR is a tariffed program, which results in the requirement that it be just and reasonable. Direct Energy R.B. at 6-7. Direct Energy and DR further claimed that PPL should be required to use late payment charges to reduce the POR and MFC percentages. Direct Energy R.B. at 2, DR R.B. at 3.

PPL responded that late payment charges are paid, and are, therefore, not uncollectible but are revenue, as reflected in its accounting for decades and repeatedly approved by the Commission. PPL M.B. at 188; PPL St. 8-RJ at 8. In addition, PPL pointed out that late payment charges are used to reduce the overall distribution of revenue requirement for customer rate classes that bear the working capital requirement associated with overdue accounts receivable. PPL averred that granting this request would result in double counting. PPL M.B. at 188. Therefore, according to PPL, should the request be granted, the late payment fees would need to be split between the POR and MFC customers, accompanied by an adjustment in base rate revenues, which would increase rates for all distribution customers. PPL St. 8-RJ; PPL M.B. at 189.

b. ALJ's Recommendation

The ALJ recommended that the Company be required to track uncollectibles by default customers and shopping customers separately, and the correct percentage can be discerned from there. The ALJ noted that the proposed percentage is supported by the past uncollectibles in total, but there is no calculation of which uncollectibles are from default customers and which are from shopping customers. According to the ALJ, this is not consistent with the terms of the settlement from which the POR program was conceived:

> 25. The Company will monitor individual EGS uncollectible percentages for small C&I customers pursuant to Section12.9.2.6 of the tariff supplement provided in Appendix A and will adjust the discount rate for an individual EGS based upon the provisions contained therein.

R.D. at 131 (quoting *Petition of PPL Electric Utilities Corporation Requesting Approval of a Voluntary Purchase of Accounts Receivables Program and Merchant Function Charge,* Docket No. P-2009-2129502 (Order entered November 19, 2009)).

The ALJ expressed concern that PPL's procedure does not require the Company to determine the actual amount of its uncollectible expenses in order to recover them. The ALJ concluded that the actual amount of the uncollectible expenses is required in order to fairly charge customers the correct amount. Therefore, the ALJ found that PPL should be directed to take the next step and determine that amount for shoppers and to determine that amount for default customers, and to collect it accordingly. The ALJ recommended that PPL's proposed increase in the POR discount rate should be delayed for ninety days until the Company provides data indicating the proportions of uncollectibles attributable to default customers and to shopping customers, to support the proper discount rate. R.D. at 133, 142, O.P. # 10.

The ALJ further recommended that if PPL does not comply with this directive then the percentage discount rates currently in effect in its POR Program should remain in effect. R.D. at 142, Ordering Paragraph No. 11.

The ALJ also stated that Direct Energy and DR had not sustained their burden of proving that their alternatives were appropriate choices for the Commission to adopt in this case. R.D. at 133.

Additionally, the ALJ concluded that late payment fees are presently added to revenues, and that is where they should remain. *Id.* at 134.

c. Exceptions

In its Exceptions, Direct Energy avers that although the ALJ correctly concluded that PPL has failed to prove its increase for the POR discount rate, the ALJ erred in directing PPL to continue the current POR/MFC discount mechanism. Instead of continuing PPL's problematic mechanism, Direct Energy recommended that PPL be required to recover the currently unbundled uncollectible accounts expense in a non-bypassable charge applicable to all customers. Direct Energy avers that PPL's POR program, which reflects total uncollectible expense in the POR discount rate, has resulted in continuing and significant increases to the POR discount rate. Direct Energy compared the January 1, 2010, POR rate of 1.32% to the proposed rate in this proceeding of 2.23%. Direct Energy further notes that if the PPL proposal is adopted, then PPL's POR program would have the highest discount rate of all the Pennsylvania EDCs. Direct Energy Exc. at 3-5.

Direct Energy avers that its proposed non-bypassable mechanism would eliminate the need to determine the specific uncollectible accounts expense for shopping customers, while allocating the uncollectible accounts expense across all customers consistent with traditional rate-making principles. According to Direct Energy, while the ALJ criticizes its proposal because it does not require a calculation of actual uncollectible accounts expense for shopping customers, the fact here is that PPL cannot make that calculation. Direct Energy opines that even the ALJ acknowledged that when the actual uncollectible accounts expense cannot be calculated, Direct Energy's approach is better than the one used by PPL, as she stated that it is "less unfair in its inherent unfairness." Direct Energy Exc. at 8 (quoting R.D. at 133).

Next, Direct Energy states that even if the ALJ's recommendation to continue PPL's current POR discount is adopted, the ALJ erred in failing to recommend adjustments to the calculation of the POR discount rate. According to Direct Energy, the Commission must direct that the initial starting point for the uncollectible accounts expense portion of the POR discount must be the same level of uncollectible accounts expense used to determine PPL's revenue requirement. From there, Direct Energy posits that the Commission should further adjust the POR discount rate to: (1) offset the uncollectible accounts expense percentage factor by the unbundled portion of the revenue PPL receives from late payment charges related to generation rates; and (2) create an administrative credit of 0.05% to the POR discount rate to return to EGSs the money PPL has collected during the POR program through the administrative component based on PPL's admitted failure to track actual incremental administrative costs and to quantify them. Direct Energy Exc. at 10-11.

In its Exceptions, DR first asserts that the ALJ should have set the POR discount at the 1.7% uncollectibles rate she adopted for ratemaking purposes. DR states that there is no real dispute in this case that the POR discount is the same as the uncollectibles rate and that PPL currently does not track uncollectibles separately as between shopping and non-shopping customers. Tr. at 404-405. Therefore, DR posits that PPL does not possess the historical data that would allow the immediate development of an appropriate uncollectible expense level, based on actual experience, for residential or commercial customers and differentiate between shopping and non-shopping customers. DR opines that any PPL proposed differentiation would be speculative, which is not permitted. According to DR, the more certain path would be to require PPL to implement a POR discount based upon an uncollectible expense rate of 1.7%, which the ALJ accepted as reasonable. DR Exc. at 3-4.

Next, DR excepts to the ALJ's decision not to require PPL to use late payment fee revenue to reduce the POR discount. DR asserts that PPL cannot, and does not, reasonably dispute the fact that applying late payment fee revenue from shopping customers to offset the CWC expense for default service results in a subsidy to default service. DR submits that it proposed a reasonable means of eliminating this subsidization by using the late payment fee revenue from shopping customers to offset the uncollectibles expense of shopping customers. According to DR, under the methodology used today, shopping customers subsidize non-shopping or default service customers with every dollar of late payment fee revenue. DR asserts that this revenue should instead be used in a manner that provides at least some benefit to shopping customers, not an exclusive benefit to default service customers as it does today. DR Exc. at 5-6.

In reply, PPL states that it fully explained why Direct Energy's non-bypassable proposal should be rejected, including the fact that the Commission recently considered and rejected the very same proposal in PPL's 2010 base rate case. Also, PPL states that if the ALJ recommendation is approved by the Commission, the Company can and fully intends to promptly comply with the recommendation to track and separately determine the uncollectible accounts expense for shopping customers. In response to the Parties' proposal that the POR discount rate be set at the 1.7% three-year average of uncollectible accounts expense accepted by the ALJ, PPL opines that the 1.7% rate understates PPL's projected uncollectible accounts expense. PPL R. Exc. at 20-21.

PPL next notes that Direct Energy and DR continue to argue that late payment charges from shopping customers offset or reduce uncollectible accounts expense. PPL asserts that is not the case as these charges represent an addition to a utility's revenues and offset accounts receivable. PPL explains that late payment charges are actually paid by customers and the revenues received from late payments are, by definition, not uncollectible. According to PPL, the proposal advanced by Direct Energy and DR would result in double counting of late payment revenues by crediting these revenues to customers twice. PPL R. Exc. at 21.

Lastly, in response to Direct Energy's proposal in regard to the administrative component of the POR discount rate, PPL claims that Direct Energy ignores the record evidence that the Company has incurred incremental expenses with its POR program. PPL asserts that the POR is a Section 1308 rate and cannot be retroactively changed. PPL R. Exc. at 21.

In its Reply Exceptions, PPLICA states that the ALJ correctly rejected the proposal that PPL implement a non-bypassable charge for recovery of uncollectibles expense currently recovered through the POR discount. PPLICA asserts that the ALJ's rejection of a non-bypassable charge reflects the many flaws inherent in this proposal, including the potential for double charging customers not eligible for PPL's POR program and the rebundling of generation, transmission and distribution charges. PPLICA requests that the Commission adopt the ALJ's recommendation. Further, PPLICA avers that the ALJ's rejection of this proposal is fully consistent with Commission precedent and the Code. PPLICA explains that the Commission addressed a similar proposal from the Retail Energy Supply Association in PPL's 2010 rate case and held that "EGSs should bear the collection risk for their own customers, either by including it in the charges to those customers or by selling their receivables to PPL at a discount." PPLICA R. Exc. at 13 (quoting *Pa. PUC v. PPL Electric Utilities Corp*., Docket No. R-2010-2161694, at 153 (Order entered December 21, 2010)). PPLICA further asserts that adoption of Direct Energy's proposal would violate Section 2804(3) of the Competition Act, 66 Pa. C.S. § 2804(3), which requires EDCs to unbundle generation, transmission and distribution rates. PPLICA R. Exc. at 12-13.

In its Replies to Exceptions on this issue, the OSBA states that although the Direct Energy language it quotes in its Exceptions does not say so, Direct Energy is addressing the residential class uncollectibles rate. The OSBA explains that for the majority of Direct Energy's Exceptions, the 1.7% is referred to as "the uncollectibles rate" when it is, in fact, just the rate for the residential customers. While the OSBA agrees with Direct Energy that the uncollectibles rate determined for the residential class should be used to develop both the residential MFC and the residential POR discount, the OSBA cautions that the 1.7% factor is not appropriate for the non-residential classes. According to the OSBA, the Small C&I and Large C&I MFC and POR discount rates should reflect the uncollectibles rates applicable to those classes. OSBA R. Exc. at 14-15.

d. Disposition

First, with regard to Direct Energy's recommendation for the use of a non-bypassable distribution charge applicable to all customers to collect uncollectible expenses, we find that PPL correctly explained that the use of a non-bypassable charge is improper and has previously been rejected in PPL's prior 2010 base rate proceeding. In that Order we held that the collection risk for shopping customers should remain with the EGSs. *Pa. PUC v. PPL Electric Utilities Corp*., Docket No. R-2010-2161694, at 95. We affirm that position in the instant proceeding. Therefore, the Exceptions of Direct Energy are denied on this issue.

Next, we agree with the ALJ's recommendation to delay the implementation of the Company's proposed increase in the POR discount percentage for ninety days. We concur with the ALJ's directive that the currently effective rates remain in effect until PPL provides the required breakdown on these expenses between shopping and non-shopping customers. Once this information is developed, the Commission will have thirty additional days to finalize an appropriate course of action. We note that the Company stated in its Replies to Exceptions that it can and fully intends to promptly comply with the ALJ's recommendation to track and separately determine the uncollectible accounts expense for shopping customers. We also agree with the ALJ that if PPL fails to provide this information, then the currently effective discount rates shall remain unchanged. Therefore, the Exceptions of Direct Energy and DR are denied on this issue.

In response to the Direct Energy and DR recommendation to offset uncollectible accounts expense with late payment fees, we are persuaded by the arguments of PPL that late payment fees do not reduce uncollectibles. We agree with PPL that late payment charges are actually paid by customers and are used to reduce the overall distribution of revenue requirement for customer rate classes that bear the working capital requirement associated with overdue accounts receivable. Accordingly, we adopt the recommendation of the ALJ on this issue and deny the Exceptions of Direct Energy and DR.

In conclusion, we address the recommendation of Direct Energy that since PPL did not track the incremental expenses under the 0.05% administrative cost component of the POR discount rate, then PPL should be directed to refund all amounts collected to date under this component until the amount PPL has collected is returned. We find it disappointing that PPL did not track these costs. The administrative component of the POR rate was designed with cost recovery of incremental costs in mind. However, the tariff did not provide for these refunds. In order to avoid a repetition of this failure, the Parties should address the issue in future proceedings so as to provide a more equitable outcome.

Going forward, we direct PPL to track and make an appropriate filing with the Commission describing all revenues and incremental costs incurred to develop, implement, and administer the POR service, including costs since inception, associated with implementation of its POR service if it desires to seek any further administrative cost recovery in the future. If, at that time, it is determined that PPL over-recovered historical administrative costs, future cost recovery will only be allowed once the historical over-recovery is netted out. Accordingly, we shall adopt the ALJ's recommendation, as modified by this Opinion and Order, and deny the Exceptions of Direct Energy.

In summary, we hold that PPL's proposed POR program discount rates remain as currently in effect for ninety days and that PPL is directed to provide the breakdown of uncollectible expenses between shopping and non-shopping customers within ninety days. If PPL does not comply with this directive, then the percentage rates currently in effect in its POR program shall remain in effect. Furthermore, the recommendations of the intervening Parties with regard to the implementation of a non-bypassable charge, the offset of late payment fees and the refund of the administrative cost component are denied, consistent with the discussion herein.

IV. CONCLUSION

We have reviewed the record as developed in this proceeding, including the ALJ's Recommended Decision and the Exceptions and Replies to Exceptions filed thereto. Based upon our review, evaluation and analysis of the record evidence, the Exceptions filed by the various Parties hereto are granted or denied, and the ALJ's Recommended Decision is modified, consistent with the discussion in this Opinion and Order; **THEREFORE,**

V. ORDERING PARAGRAPHS

IT IS ORDERED:

1. That the Exceptions of the Office of Small Business Advocate, Direct Energy Services, PP&L Industrial Customer Alliance, the Commission on Economic Opportunity and Dominion Resources, filed on November 8, 2012, are denied, consistent with this Opinion and Order.

2. That the Exceptions of PPL Electric Utilities Corporation, the Office of Consumer Advocate, the Bureau of Investigation and Enforcement, filed on November 8, 2012, are granted in part, consistent with this Opinion and Order.

3. That the Recommended Decision of Administrative Law Judge Susan D. Colwell, issued on October 19, 2012, is adopted as modified by this Opinion and Order.

4. That PPL Electric Utilities Corporation shall not place into effect the rates, rules and regulations contained in Supplement No. 118 to Tariff – Electric Pa. P.U.C. No. 201, as filed.

5. That PPL Electric Utilities Corporation is authorized to file tariffs, tariff supplements and/or tariff revisions, on less than statutory notice, and pursuant to the provisions of 52 Pa. Code §§ 53.1, *et seq.,* and 53.101, designed to produce an annual distribution rate revenue increase of approximately $71.065 million, to become effective for service rendered on and after January 1, 2013.

6. That PPL Electric Utilities Corporation shall file detailed calculations with its tariff filing, which shall demonstrate to the Commission's satisfaction that the filed tariff adjustments comply with the provisions of this final Opinion and Order.

7. That PPL Electric Utilities Corporation shall allocate the authorized increase in operating distribution revenue to each customer class, and rate schedule within each customer class, in the manner prescribed in this Opinion and Order.

8. That PPL Electric Utilities Corporation shall comply with all directives, conclusions, and recommendations contained in the body of this Opinion and Order, which are not the subject of an individual directive in these ordering paragraphs, as fully as if they were the subject of a specific ordering paragraph.

9. That the Formal Complaints filed by the Office of Consumer Advocate, the Office of Small Business Advocate and PP&L Industrial Customer Alliance are sustained in part, consistent with this Order.

10. That the Formal Complaints filed by William Andrews; Tracey Andrews; Eric Joseph Epstein; Dave A. Kenney; Roberta Kurrell; Donald Leventry; John G. Lucas and Helen Schwika, and any other Formal Complaint not specifically noted but filed prior to issuance of this Opinion and Order, are hereby dismissed.

11. That, upon Commission approval of the tariff, tariff supplements and/or tariff revisions, submitted in compliance with this Opinion and Order, the investigation at Docket Number R-2012-2290597 shall be marked closed.

BY THE COMMISSION,

Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: December 5, 2012

ORDER ENTERED: December 28, 2012

Pennsylvania Public Utility Commission

v.

PPL Electric Utilities Corporation
Docket No. R-2012-2290597

Commission Tables Calculating Allowed Revenue Increase

TABLE I
PPL Electric Utilities Corporation
INCOME SUMMARY
R-2012-2290597
($000s)

Commission Final Allowance

		Pro Forma Present Rates (Revised) [1]	Commission Adjustments [2]	Commission Pro Forma Present Rates	Commission Revenue Increase	Total Allowable Revenues
		(1)	(2)	(3) = (1) + (2)	(4)	(5) = (3) + (4)
1.	Operating Revenue	780,425	0	780,425	71,030	851,455
2.	Expenses:					
3.	O & M Expense	417,869	(11,966)	405,903	1,759	407,662
4.	Depreciation	139,719	0	139,719	0	139,719
5.	Taxes, Other	53,516	(734)	52,782	4,149	56,931
6.	Income Taxes:					
7.	State	1,571	1,346	2,917	6,506	9,423
8.	Federal	(7,321)	4,245	(3,076)	20,516	17,440
9.	Deferred Inc.	28,861	0	28,861	0	28,861
10.	ITC	(915)	0	(915)	0	(915)
11.	Total Expenses	633,300	(7,109)	626,191	32,930	659,120
12.	Income Available for Return	147,125	7,109	154,234	38,100	192,334
13.	Rate Base	2,420,963	(13,237)	2,407,726		2,407,726
14.	Rate of Return	6.08%		6.41%	38,100 (0)	7.98822%

(1) PPL Exh. Future-1 Revised 7-16-12; Schedule D-1, Column 6.
(2) From Table IV - Adjustments

TABLE II
PPL Electric Utilities Corporation
RATE OF RETURN
R-2012-2290597

Commission Final Allowance

		Structure	Cost	After-Tax Weighted Cost	Effective Tax Rate Complement	Pre-Tax Weighted Cost Rate
		(1)	(2)	[(3)=(1)x(2)]	(4)	[(5)=(3)x(4)]
1.	Total Cost of Debt			2.70710%		2.70710%
2.	Long-term Debt	49.22%	5.50%	2.70710%		2.71%
3.	Short-term Debt	0.00%	0.00%	0.00000%		0.00%
4.	Preferred Stock	0.00%	0.00%	0.00000%	0.585065	0.00%
5.	Common Equity	50.78%	10.40%	5.28112%	0.585065	9.03%
6.	Totals	100.00%		7.98822%		11.74%
7.	Pre-Tax Interest Coverage (11.74% / 2.70710%)	4.336%				
8.	After-Tax Interest Coverage (7.872% / 2.70710%)	2.951%				
9.	Tax Rate Complement (1-(35%+(9.99% X (1-35%))	58.50650%				

TABLE III
PPL Electric Utilities Corporation
REVENUE FACTOR
R-2012-2290597

Commission Final Allowance

1.	100%	100.0000%
2.	Uncollectible Accounts Factor	-2.23000%
3.	(Line 1-Line 2)	97.7700%
4.	PUC, OCA, OSBA Assessment Factors	0.2460%
5.	Gross Receipts Tax (GRT) (Modified per Commission Order)	5.7684%
6.	Other Tax Factors (PA CST)	0.0746%
7.	(Sum of Lines 4, 5 and 6)	6.0890%
8.	Effective Assmt/GRT/CST (Line 7)	6.0890%
9.	Factor after Assmt, GRT and CST (Line 3 - Line 8)	91.681%
10.	State Corporate Net Income Tax Rate	9.990%
11.	Effective State Income Tax Rate (Line 9 x Line 10)	9.1589%
12.	Factor After Local and State Taxes (Line 9 - Line 11)	82.5220%
13.	Federal Corporate Income Tax Rate	35.00%
14.	Effective Federal Income Tax Rate (Line 13 x Line 12)	28.883%
15.	Revenue Factor (100% - Effective Tax Rates); (Line 1 - (Lines 2, 3, 8, 11 and 14))	53.6393%

TABLE IV
PPL Electric Utilities Corporation
SUMMARY OF COMMISSION ADJUSTMENTS
R-2012-2290597
($000)

Commission Final Adjustments

	Adjustments	Rate Base	Revenues	Expenses	Depreciation	Taxes-Other	State Income Tax	Federal Income Tax
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1.	RATE BASE:							
2.	CWC:							
3.	Int. & Div. (Table VI)	(63)						
4.	Taxes (Table V)	174						
5.	O & M (Table VI)	(13,348)						
6.	TAXES OTHER:							
7.	Gross Receipts Tax (Table XI)					(259)	26	82
8.	Capital Stock Tax (Table X)					(475)	47	150
9.	REVENUES:							
			0				0	0
10.	EXPENSES:							
11.	Rate Case Normalization - PPL Revision			1,200			(120)	(378)
12.	Environmental Management			(103)			10	33
13.	Storm Damage Claim - PPL Revision			(3,500)			350	1,103
14.	Office of General Counsel			(1,200)			120	378
15.	Office of the Chairman			(387)			39	122
16.	Consumer Education: Act 129 Move to CER Rider			(2,494)			249	786
17.	Consumer Education: Pre Act 129			(5,482)			548	1,727
18.	DEPRECIATION:							0
					0		0	0
					0		0	0
19.	TAXES:							
20.	Interest Synchronization (Table V)						77	242
21.	TOTALS	(13,237)	0	(11,966)	0	(734)	1,346	4,245

Notes:

Rate Case Expense and Office of General Counsel: PPL Exhibit Future 1-Revised presents PPL's revised rate case expense which removes $1.2 million representing the double counting of OGC expense. See PPL Future Future 1-Revised Schedule D-6. This $1.2 needs to be added back to Rate Case Expense to reflect adoption of the ALJ's recommended treatment of this expense.

Storm Damage Claim: PPL reduced its claim due to the unavalibility of this type of insurance.

Office of General Counsel: This duplicated expense was removed from the Rate Case Expense claim in PPL Future 1-Revised Schedule D-6. The ALJ's R.D. reflected this as a reduction to the OGC expenses.

Consumer Educatio Pre Act 129: The ALJ's R.D. allowed this expense only to the end of the FTY but the adjustment was inadvertantly excluded from the Tables attached to the R.D.

TABLE V
PPL Electric Utilities Corporation
INTEREST SYNCHRONIZATION
R-2012-2290597

Commission Final Adjustments

		Amount (000)
1.	Company Rate Base Claim (PPL Exh. Furure 1-Revised Sch. C-1)	$2,420,963
2.	Commission Rate Base Adjustments (From Table IV)	($13,237)
3.	Commission Rate Bas (Line 1 - Line 2)	$2,407,726
4.	Weighted Cost of Debt (From Table II)	2.7071%
5.	Commission Interest Expense (Line 4 x Line 3)	$65,180
6.	Company Claim (PPL Exh. JMK 2 p. 28, Line 1)	$65,947
7.	Commission Adjustment (Line 6 - Line 5)	$767
8.	Company Adjustment	$0
8.	Net Commission Interest Adjustment (Line 7 - Line 8)	$767
10.	State Corporate Net Income Tax Rate	9.99%
11.	State Corporate Net Income Tax Adjustment (Line 10 x Line 9) (Flow to Table IV)	**$77**
12.	Net Commission Adjustment for Federal Taxable Income (Line 9 - Line 11)	$690
13.	Federal Income Tax Rate	35.00%
14.	Federal Income Tax Adjustment (Line 13 x Line 12) (Flow to Table IV)	**$242**

TABLE VI
PPL Electric Utilities Corporation
CASH WORKING CAPITAL: O & M COMPONENT
R-2012-2290597

Commission Allowance

		(000)
1.	Total O&M Expense per PPL (PPL Exh Future 1-Revised Sch. C-4, p. 2)	$465,055
2.	Jurisdictional Factor (See Line 15 Below)	85.973%
3.	Jurisdictional O&M Expense (Line 1 X Line 2)	$399,823
4.	Commission O&M Adjustments (From Table IV)	($11,966)
5.	Net O&M Expense (Line 3 - Line 4)	$387,857
6.	O&M Expense per Day (Line 5 / 365 days)	$1,063
7.	Average Lag Days (ALJ R.D. at 19-20; Order at Section II C.)	9.60
8.	Commission Allowed O&M CWC Requirement (Line 6 X Line 7)	$10,201
9.	Company Claim (PPL Furure 1-Revised Sch. C-4, p. 2)	$27,391
10.	Jurisdictional Portion of Company Claim (Line 2 X Line 15)	$23,549
11.	Commission Adjustment to Rate Base (Line 8 - Line 10); (Flow to Table IV)	**($13,348)**

12.	O&M Expense Per Company Filing:	
13.	Total O&M (PPL Future 1-Revised Sch. D-1, Col. 5)	$486,045
14.	Jurisdictional O&M (PPL Future 1-Revised. D-1, Col. 6)	$417,869
15.	Jurisdictional Factor (To Line 2 above)	85.973%

TABLE VII
PPL Electric Utilities Corporation
CASH WORKING CAPITAL: ACCRUED TAXES
R-2012-2290597

Commission Allowance

		Pro Forma Taxes (000)	Twelve-Month Accrued Factor per Company	Accrued Taxes (000)
		(1)	(2)	(3) = (1) X (2)
1.	Federal Income Tax	($1,312)	(5.95000%)	$78
2.	PA Corporate Net Income Tax	$11,864	(3.86000%)	($458)
3.	PA Gross Receipts Tax (See Below)	$47,861	33.64000%	$16,100
4.	PA Capital Stock Tax	$2,017	(3.86000%)	($78)
5.	PA PURTA Tax	$2,832	21.14000%	$599
6.	Total Accrued Taxes (Sum of Lines 1 - 5)			$16,241
7.	Accrued Taxes per ppl (PPL Exh. Future 1-Revised, Sch. C-4, p. 4, Line 6)			$16,068
8.	Adjustment to Accrued Taxes (Line 6 - Line 7) (Flow to Table IX)			**$173**

PA Gross Receipts Tax

9.	Per Company (Future Revised Schedule D-11 p 13)	$43,670
10.	Adjustment Due To Allowed Revenue Increase (Allowed Increase X 0.059)	$4,191
		$47,861

PA Capital Stock Tax

11.	Per Company (Future Revised Schedule D-11 p. 2)	$1,954
12.	Adjustment Due To Allowed Revenue Increase (Allowed Increase X 0.0089)	$63
		$2,017

TABLE VIII
PPL Electric Utilities Corporation
CASH WORKING CAPITAL: INTEREST PAYMENTS
R-2012-2290597

Commission Allowance

		(000)
1.	Rate Base (Table I)	$2,407,726
2.	Weighted Average Cost of Debt (Table II)	2.70710%
3.	Interest Expense (Line 1 x Line 2)	$65,180
4.	Daily Amount of Interest Expense (Line 3 / 365)	$178.57
5.	Interest Payment Lag Days	32.90
6.	Commission CWC Interest (Line 4 x Line 5)	$5,875
7.	Company Claimed CWC Interest	$5,938
8.	Commission Adjustment (Flow to Table IX)	($63)

TABLE IX
PPL Electric Utilities Corporation
CASH WORKING CAPITAL
R-2012-2290597

		(000)
1.	O&M Expense (PPL Future 1-Revised, Sch. C-4 p. 2, Line 4)	$27,391
2.	Average Prepayments (PPL Future 1-Revised Sch. C-4, p. 3, Line 15)	$3,174
3.	Accrued Taxes (PPL Future 1-Revised, Sch C-4 p. 4, Line 6)	$16,068
4.	Interest Payments (PPL Future 1-Revised Sch. C-4, p. 5, Line 9)	($8,061)
5.	Total CWC per Company (Sum of Lines 1 through 4)	$38,572
6.	Jurisdictional CWC	$31,593
Commission Adjustments		
7.	Calc O&M Difference (From Table VI Row 11)	($13,348)
8.	Calc Accrued Tax Difference (From Table VII)	$173
9.	Calc Interest Payment Difference (From Table VIII)	($63)
10.	Commission CWC Adjustments (Lines 7 + 8 + 9)	($13,237)
11.	Total CWC (Line 6 + Line 10)	$18,356

TABLE X
PPL Electric Utilities Corporation
CAPITAL STOCK TAX (CST)
R-2012-2290597

		(000) Present Rate Adjustment		(000) Proposed Rate Adjustment	
	Net Income				
1.	2008	$87,403		$87,403	
2.	2009	$103,885		$103,885	
3.	2010	$80,572		$80,572	
4.	2011	$129,591		$129,591	
5.	2012	$97,491		$140,630	
6.		$498,942		$542,081	
7.	Average (Line 6 / 5)	$99,788		$108,416	
8.	Net Worth at December 31, 2012 (Note 2)	$1,790,672		$1,833,811	
9.	Pa Capital Stock value (Per Statutory Formula)		$1,196,704		$1,258,269
10.	Statutory Exemption		($160)		($160)
11.	Value of Capital Stock less Statutory Exemption		$1,196,544		$1,258,109
12.	Apportionment Percentage		95.4053%		95.4053%
13.	Pa CST Value (Line 11 x Line 12)		$1,141,566		$1,200,302
14.	PA CST at 0.89 mills (Line 13 x 0.89 mills)		$1,016		$1,068
15.	Less: PA Education tax credit		($217)		($217)
16.	PA CST at Proposed Rates (Line 14 + Line 15)		$799		$851
17.	Less: PA CST at Present Rates (PPL Sch D-11 p. 2)		$1,941		$799
18.	Jurisdictional Allocation (Note 3 Below)		41.6070%		41.6070%
19.	Adjustment to PA CST (Forward to Table IV)		($475)		$52

	Note 1	
20.	Net Income at Present Rates	$97,491
21.	Net Income from Proposed Rate Increase (Table XI Line 9)	$ 38,100
22.	Total 2012 Net Income (Line 19 + Line 20)	$135,591
	Note 2	
23.	Net Worth at Present Rates	$1,790,672
24.	Net Worth from Proposed Rate Increase (Table XI Line 9)	$ 38,100
25.	Total 2012 Net Worth (Line 22 + 23)	$1,828,772
	Note 3	
26.	Total PPL Electric (PPL Exhibit JMK-2 p. 22)	$1,954
27.	PA Jurisdictional (PPL Exhibit JMK-2 p. 22)	$813
28.	Allocation for PA Jurisdictional (Line 26 / Line 25)	41.6070%

TABLE XI
PPL Electric Utilities Corporation
GROSS RECEIPTS TAX (GRT)
R-2012-2290597

	Commission Allowance	($000)
1.	Base for GRT (PPI Exh JMK2 p. 26)	$744,568
2.	Less Uncollectible Accounts Expense (PPL Exh JMK 2 p. 51)	($14,055)
3.	Net Gross Receipts (Line 1 - Line 2)	$730,513
4.	GTR Rate	5.90%
5.	GRT on Net Gross Receipts (Line 4 X Line 5)	$43,100
6.	PA Jurisdictional Base for GRT (Line 1 X (1 - 0.0059))	$740,175
7.	Less Uncollectible Accounts Expense (PPL Exh JMK 2 p. 51)	($14,055)
8.		$726,120
9.	GTR Rate	5.90%
10.	GRT on Jurisdictional Net Gross Receipts (Line 9 X Line 8)	$42,841
11.	Reduction to GRT by Excluding Uncollectible Accounts Expense (Line 5 - Line 10) (Flow to Sch. IV)	($259)

Table XII
PPL Electric Utilities Corporation
R-2012-2290597
RECONCILIATION OF
Operating Revenue and Applicable Tax
Commission Allowed Rate Increase
(000)

Commission Allowance

Line No.	Description	Amount
1.	Commission Allowed Increase (Table I)	$71,030
	Provision for Uncollectibles (Line 1 x 2.23%)	$1,584
2.	PUC, OCA, OSBA Assessment	$175
	PA Gross Receipts Tax ((Line 1 - Line 3) * 59 mils)	$4,097
3.	PA Capital Stock Tax (Table X Line 16)	$52
4.	Sub Total	$5,908
5.	Taxable Income for PA CNI Tax (Line 1 - Line 4)	$65,122
6.	PA CNI Tax (Line 5 * 9.99%)	$6,506
7.	Federal Taxable Income (Line 5 - Line 6)	$58,616
8.	Federal Income Tax (Line 7 * 35%)	$20,516
9.	Operating Income (Line 7 - Line 8) (See Table I, Col. 4, Line 12)	$38,100

STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

ILLINOIS-AMERICAN WATER COMPANY	)	
	)	Docket No. 16-0093
Proposed general increase in water and sewer	)	
rates.	)	

<u>INITIAL BRIEF OF ILLINOIS-AMERICAN WATER COMPANY</u>

Dated: August 31, 2016

TABLE OF CONTENTS

Page No.

I. INTRODUCTION

One issue in this case dwarfs all others—the appropriate cost of equity. The difference in revenue requirement between the Staff position on cost of equity and Illinois-American Water Company's (IAWC) is approximately $20 million. And the outcome will have a significant effect on IAWC, which must compete for capital, not only with other enterprises, but with other American Water affiliates.

The Company proposes a return on equity of 10.75%. Staff, by contrast, proposes an unprecedented low of 8.04%. Staff's proposal, however, is based on unsupportable Discounted Cash Flow (DCF) results and is too low to be given consideration. And there are very serious consequences of even entertaining a return on equity as low as Staff's. IAWC already has the lowest authorized ROE of any utility in the American Water system. The subsidiaries with competitive rates of return are much more likely to attract the capital necessary to address aging water infrastructure in a more pro-active, accelerated fashion. Less competitive subsidiaries (like IAWC) will have to settle for what is needed to address these issues reactively. Adopting Staff's proposals would simply make this situation untenable.

American Water's customers in Illinois have been provided with exceptional service. The Company is proud of its achievements since the last rate case in the areas of service quality and reliability, and is committed to carrying these successes forward into the future. And this achievement has been reached efficiently: in the five years since the Company's last case, IAWC has *reduced* O&M expenses below the amount authorized by the Commission in the last rate case. If the Company is to continue to provide such exceptional service and efficient operations it must be provided with the continued means to do so. Although this Commission has recognized that efficient operations are the norm and do not entitle the utility to premium returns, this does not mean that a utility company should not be rewarded for truly excellent and exemplary results. The excellent service and productivity gains achieved by the Company warrant providing IAWC a rate of return on equity at the highest end of the range of reasonableness. In sum, Mr. Moul's recommendation of 10.75% is the most reasonable presented and should be adopted.

II. CAPITAL STRUCTURE AND RATE OF RETURN

A. Contested Issues

1. Cost of Common Equity

a. Summary of Recommendations

The differences in the recommended rates of return on equity (ROE) sponsored by the parties in this case are considerable and significant:

PARTY	RECOMMENDATION
Company	10.75%
IIWC/FEA/CUB	9.0%
Staff	8.04%

Although the Illinois Industrial Water Consumers, the Federal Executive Agencies and Citizens Utility Board (IIWC/FEA/CUB) IIWC/FEA/CUB recommendation is low, Staff's recommendation is literally unprecedented. Staff is recommending that the Commission authorize the lowest ROE it has ever authorized since 1968, according to the Rate Case History Report[1] published on the Commission's web site. (IAWC Ex. 10.00R at 2-3; IAWC Ex. 10.04R.) Company witness Paul Moul, consequently observed that "The investment community would be alarmed if the Commission were to adopt Staff's proposal." (IAWC Ex. 10.00R at 6:95-96.)

[1] *Available at* www.icc.illinois.gov/reports/report.aspx (published Aug. 24, 2016) (last accessed Aug. 31, 2016). In Docket No. 95-SF, the Commission authorized a 5.63% return on equity for Nordic Park Water. However, the overall rate of return of 9.71% exceeded the cost of equity. Since rate orders issued prior to the year 2000 are not available online, it cannot be determined if the return on equity represented on the report is correct.

We will demonstrate, *infra,* that because it is based on insupportably low Discounted Cash Flow (DCF) results the Staff recommendation is simply too low to be given consideration. It is below all reasonable recommendations: far more than 150 basis points below rates of return on equity allowed by all regulators in the country, more than 150 basis points below the returns allowed in the water industry, more than 150 basis points below returns allowed for IAWC's sister companies and far below any return authorized by this Commission. We will further show the infirmities, particularly related to the DCF, that affect both Staff's and, to a lesser extent, IIWC/FEA/CUB's recommendation. We will further detail why the FERC has taken a different approach to the DCF that is more reflective of reality. We will then explain the very serious consequences of even entertaining a rate of return on equity as low as Staff and IIWC/FEA/CUB. And, finally, we will show why the excellent service and productivity gains achieved by the Company warrant providing IAWC a rate of return on equity at the highest end of the range of reasonableness. In sum, Mr. Moul's recommendation of 10.75% is the most reasonable presented and should be adopted.

b. Framework for Deciding the Company's Cost of Equity

Although rates of return on equity provided to utilities around the country are certainly not dispositive on this Commission, they do provide a valuable framework with which the issue of the Company's cost of equity can be evaluated and decided. As shown below, by any measure, the recommendations of the Staff and IIWC/FEA/CUB in this case are well below the norm.

Those rates of return on equity for example are well below the return granted by other state regulatory commissions as reported by Regulatory Research Associates (RRA). According to the RRA publication dated April 15, 2016, the average authorized equity returns for electric utilities were:

YEAR	EQUITY RETURN
2011	10.29%
2012	10.17%
2013	10.03%
2014	9.91%
2015	9.85%
2016	10.26%

(IAWC Ex. 10.00R at 3.)

Additionally, all the witnesses on this subject used a proxy group to determine their equity cost recommendations. It is telling that the ROEs for the Water Group companies as determined by their regulators, according to the AUS Monthly Utility Reports dated April 2016 that was provided as part of Mr. Gorman's workpapers, are:

COMPANY	ALLOWED ROE
American States Water Co.	9.43%
American Water Works Co., Inc.	9.75%
Aqua America, Inc.	9.79%
Artesian Resources Corp.	10.00%
California Water Service Group	9.43%
Connecticut Water Service, Inc.	9.63%
Middlesex Water Company	9.75%
SJW Corporation	9.43%
York Water Company	NM
Average	9.65%

(IAWC Ex. 10.00R at 4.)

Finally, the authorized ROEs of the Company's affiliates, as determined by their regulators are:

AMERICAN WATER SUBSIDIARY	ALLOWED ROE
Pennsylvania-American Water Co.	10.25%
Hawaii-American Water Co.	10.20%
Maryland-American Water Co.	10.00%
Tennessee-American Water Co.	10.00%
California-American Water Co.	9.99%
Indiana-American Water Co.	9.75%
New Jersey-American Water Co.	9.75%
Virginia-American Water Co.	9.75%
West Virginia-American Water Co.	9.75%

Missouri-American Water Co.	9.5%-9.75%
Kentucky-American Water Co.	9.70%
New York American Water Co.	9.65%
Iowa-American Water Co.	9.41%
Illinois-American Water Co.	9.34%

(IAWC Ex. 10.00R at 5.) Notably, the return for IAWC under Staff's proposal would be 157 basis points below the next higher return.

Utility ROEs are estimated using financial models that seek to explain investor expectations, including the DCF and CAPM models. In this case, predictions of investor expectations, as expressed in the Staff and IIWC/FEA/CUB DCF methods for estimating ROE, clearly do not line up with recent observations of investors. When averaged with the CAPM indications of ROE, the DCF points to unreasonably low Staff's and IIWC/FEA/CUB's recommendations. The record shows this in numerous ways.

First, the most striking indication of the tendency of the DCF to understate the true cost of equity is the simple fact that applying the DCF model to comparable companies yields results that are far lower than these companies' current authorized ROEs. The companies in Staff's Water Group, for example, have authorized returns of up to 10%, the average being 9.65%. (IAWC Ex. 10.00R at 4.) Yet, when Staff prepared a DCF analysis to explain the investor required ROE for these companies, the results congregate in the high six percent to low seven percent range. (ICC Staff Ex. 5.0, Sch. 5.05.) Staff's DCF approach, therefore, is not only inconsistent with investor requirements, it is also egregiously out of synch with the findings of regulators across the nation.

Second, the DCF results presented in this case are consistently below the witnesses' respective CAPM results, as well as the results of other methods employed as a "reasonableness" check on the DCF and CAPM. (ICC Staff Ex. 5.0, Sch. 5.05; IIWC/FEA/CUB Ex. 1.0 Appx. B at 36; IAWC Ex. 10.00 (Rev.) at 32, 42.) This is true for all of the witnesses.

The consistently low DCF returns are not a sign of consensus that IAWC's cost of equity has decreased from the 9.34% currently authorized. The uniformity of these results merely serves as confirmation that the DCF understates investors' true return requirements when mechanically applied in turbulent, anomalous market conditions. DCF results simply begin to break down when the variables for the DCF model are culled from the type of market that exists today—a market where historically low interest rates coupled with historically high stock prices and unusual global volatility (economic and otherwise) has turned a conventional approach into a dysfunctional one. (*See* IAWC Ex. 10.00R at 8 (noting the DCF model rests on assumptions about cash flows that take place too far in the future to permit precision in forecasting).) Indeed, Staff's DCF results lie in the range of 7.24% to 7.51%. (ICC Staff Ex. 5.0 at 14.) This is such a shockingly low equity cost recommendation—the high end of the range is more than 200 basis points *below* the average returns being determined across the country—as to raise serious questions as to whether the DCF is reliable, at all, in the current environment. And, certainly, it dispels the notion that Staff's DCF construct has any real world value.

Other parties may argue that lower ROEs are to be expected in a low interest rate environment: since banks pay savers less interest, equity investors should be willing to accept lower returns. This theory, however, is wrong. Investors do *not* expect lower interest rates to translate to lower equity returns. It is for this very reason, as we show, *infra,* that FERC recently adopted a new ROE policy that abandons the long-standing practice of making post-hearing adjustments to ROEs based on U.S. Treasury yields. The "mounting evidence that U.S. Treasury bond yields are not necessarily a reliable one-for-one indicator of changes in investor-required returns" led FERC to conclude that its policy could no longer be justified. *Mass. Att'y Gen. v. Bangor Hydro-Electric Co*., 147 FERC 61,234 at ¶ 11 (June 19, 2014) (hereinafter, *Order 531*).

Furthermore, it is clear from recent Federal Reserve policy pronouncements that the direction of interest rates will be up, not down. (IAWC Ex. 10.00R at 12.)

For all of these reasons, the technical discussion of the Company's cost of equity must also be informed by the real world reality of determinations made by other regulators and by the market generally. These real world discussions counsel that an arid mechanical exercise that produces costs of equity that lie more than 150 basis points below authorized rates of return, or which are based on DCF results in the 6% to 7% range, are simply at war with reality and cannot be seriously considered. In fact, the results produced by Staff's analysis show figures which cannot realistically represent a fair rate of return on common equity. This becomes particularly apparent in Ms. Kight-Garlisch's DCF analysis, where four of her Water Sample DCF results are below 7%. (ICC Staff Ex. 5.0, Sch. 5.05.) The yield on public utility debt is 3.96% for A-rated and 4.70% for Baa-rated bonds. (IAWC Ex. 10.00R at 14.) The cost of equity exceeds this spread by a meaningful margin based on the relationship of debt and equity historically. (*Id*.)

c. Overview of Recommendations.

The Commission has historically given substantial weight to DCF and CAPM results. For this reason, knowledge of the mathematical expression of these models is assumed and only a brief description of each is provided.

The underlying theory of the DCF is that an investment in a utility's stock is worth the present value of future dividends, discounted at a rate commensurate with the risk of the investment. (ICC Staff Ex. 5.0 at 5-6.) The inputs of the DCF model are current stock price, expected dividend, and expected growth rate. (IAWC Ex. 10.00 (Rev.) at 17-18; *see also* IIWC/FEA/CUB Ex. 1.0 Appx. B at 22-23.) The stock price and expected dividend are observable and fairly non-controversial. The expected growth rate, however, is subject to considerable judgment, and greatly influences the calculation of the investors' required return.

All other inputs being the same, DCF results of investors' required return will increase as the growth rate used in the calculation increases. (IAWC Ex. 10.00 (Rev.) at 19-20.)

There are several variants of the DCF. The so-called "single stage" or "constant growth" DCF uses one expected growth rate to calculate the future dividend stream. (ICC Staff Ex. 5.0 at 7.) The "non-constant" growth DCF assumes dividend growth for an initial period (usually five years) often followed by a lower growth rate for the remaining measurement period. (IAWC Ex. 10.00 (Rev.) at 21-32; IIWC/FEA/CUB Ex. 1.0 Appx. B at 23-27.) IIWC/FEA/CUB witness Gorman used non-constant DCF models, and Staff witness Kight-Garlisch used a used non-constant, multi-stage DCF. (IIWC/FEA/CUB Ex. 1.0 Appx. B at 29-35; ICC Staff Ex. 5.0 at 7-14.) Mr. Moul used a constant model only. (IAWC Ex. 10.00 at 21-32.) Mr. Moul explained that the non-constant DCF model is not widely used in regulatory proceedings. (IAWC Ex. 10.00R at 8.) "Rather than providing a direct expression of the DCF result, i.e., $D_1 / P_0 + g$, the non-constant DCF model is solved by estimating specific future cash flows and then solving for the result by iteration…the basic fallacy of the non-constant DCF model rests with a set of problematic assumptions of specifying cash flows that are too far out into the future to permit a reasonable and reliable result. That is to say, cash flows extending many years into the future become less precise as the estimates are extended." (IAWC Ex. 10.00R at 7-8.)

All of the witnesses also used the CAPM. (IAWC Ex. 10.00 at 37-42; ICC Staff Ex. 5.0 at 15-26; IIWC/FEA/CUB Ex. 1.0 Appx. B at 36-44.) The theory behind the CAPM approach is that an investor's return equals a risk free rate, plus an associated risk premium. (ICC Staff Ex. 5.0 at 15-16.) The required inputs for this model are an estimate of the 30-year Treasury risk-free rate, beta (a measurement of the systemic risk associated with a stock), and a market risk premium. (*Id.*; *see also* IAWC Ex. 10.00 (Rev.) at 37.) Like the DCF, the CAPM model is sensitive to the variables used, especially the risk-free rate and market risk premium.

The essential flaw inherent in Staff's CAPM analysis is that the Staff witness's Treasury bond yield, which is a spot yield on April 7, 2016, does not reflect the expected increase in interest rates. (IAWC Ex. 10.00R at 13-14.) The Federal Open Market Committee policy is in the process of moving from an extremely accommodative to more normal monetary policy. (IAWC Ex. 10.00R at 12-13.) All recognized forecasts indicate a future rise in interest rates. (*Id.*) To gain a consensus view of future interest rates, Mr. Moul tabulated the forecasts of yields on 10-year Treasury notes published by a variety of well recognized and investor-influencing sources. He chose the 10-year Treasury note because it is available on a consistent basis across all sources. The comparisons are:

	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**Change in Basis Points**
Blue Chip	2.03%	2.57%	3.30%	3.70%	3.90%	4.10%	207
Value Line	2.10%	2.60%	3.00%	3.50%	3.70%	NA	160
EIA	2.57%	2.72%	3.27%	3.85%	3.83%	3.73%	120
IHS Global Insight	2.60%	2.85%	3.36%	3.72%	3.72%	3.72%	112
CBO- The Budget and Economic Outlook	2.80%	3.50%	3.80%	4.00%	4.10%	4.10%	130

(*Id*. at 13.) All of these interest rate forecasts indicate a significant rise in interest rates, on the order of 112 to 207 basis points, showing that Staff's CAPM result is understated.

The DCF and CAPM formulas are applied to a group of comparable companies with operating characteristics and risk profiles similar to the utility under review. In this case, each witness applied one or more variants of the DCF and CAPM to comparable companies; IAWC's comparable companies consisted of water companies only, (IAWC Ex. 10.02, Sch. 3 at 2), while Staff and IIWC/FEA/CUB used two groups, once each for gas/public utilities and water. (ICC Staff Ex. 5.0 at 3-5; IIWC/FEA/CUB Ex. 1.2 Appx. B.) Here are the range of results:

Party	DCF	CAPM	Overall
IAWC[2]	9.89%	10.93%	10.75%
IIWC/FEA/CUB[3]	6.82 – 9.48%	9.20%	9.00%
Staff[4]	7.24 – 7.51%	8.8 – 8.9%	8.04%

Staff's ROE, based on the DCF figures, is striking. The Commission has not imposed an ROE this low in the 40+ year history it has been keeping track of ROEs and publishing them. (IAWC Ex. 10.00R at 2-3.) Similarly, the low end of IIWC/FEA/CUB's DCF range is equally indefensible—indeed, lower even than Staff's DCF low. Obviously, a DCF that is so indefensibly low should not be used to drag down the cost of equity into such unchartered depths. Such DCF results, which are at war with financial reality, are just not rational.

d. Staff's and IIWC/FEA/CUB's DCF results are anomalous and unrepresentative of investor expectations.

The Staff DCF returns for utilities in the Water Group congregate in the high six percent range. (ICC Staff Ex. 5.0, Sch. 5.05.) These results, when considered in context with other financial and economic indicators, are untenable:

IAWC current authorized return	9.34%[5]
Average Water Group authorized return	9.65%[6]
Average American Water authorized return	9.75%[7]
Aqua Illinois authorized return	9.81%[8]
Average electric utility authorized return	10.26%[9]
S&P500 expected return	12.03%[10]

Moreover, the Commission found not even two years ago, that investors in Aqua required a return of 9.81%. *See Aqua Ill. Co.*, Docket 14-0419, Order at 49 (March 25, 2015). Yet,

---

2 (IAWC Exs. 10.00 at 4, 10.00R at 29-30.)_
3 (IIWC/FEA/CUB Ex. 1.0 Appx. B at 36, 44-45.)
4 (ICC Staff Ex. 5.0 at 14, 26, 31.)
5 (IAWC Ex. 10.00 at 3.)
6 (IAWC Ex. 10.00R at 4.)
7 (IAWC Ex. 10.00R at 5.)
8 (IAWC Ex. 1.00R at 2.)
9 (IAWC Ex. 10.00R at 3.)
10 (ICC Staff Ex. 5.0 at 20.)

according to Staff, investors in a company offering the same services in the same state expect to earn nearly 180 basis points less? One must question why a person would invest in IAWC when much greater returns are available by investing in Aqua. An ROE discrepancy of this magnitude would place IAWC at a considerable competitive disadvantage relative to Aqua. Like Aqua, IAWC pursues a "win-win" growth strategy by expanding its business through the acquisition of small, troubled systems. (IAWC Ex. 1.00R at 7.) Investment capital would necessarily favor Aqua's 9.81% return over the returns recommended for IAWC here. (*Id.*)

The fact that ROE estimates by means other than the DCF *consistently* produce greater returns is another reason for concern that the DCF generally understates the indicated return for all witnesses, and this is especially so for Staff. Staff's Water Group DCF is 7.24%, while the CAPM is 8.80% for Staff's Water Group. (ICC Staff Ex. 5.0 at 14, 26.) Certainly the DCF and CAPM should not be expected to predict the exact same cost of equity, but a difference of 156 basis points should raise serious questions. These questions are answered when considered in the context of the figures cited above. Ignoring this disparity by simply averaging the results produces a figure that is *less* likely to represent investor expectations rather than more. Calculating an average with a below-average figure necessarily yields a below-average "average."

IIWC/FEA/CUB's CAPM results (8.50% to 9.80%) are also greater than its DCF (7.71% to 8.75%), though not to the same degree as Staff's, depending on which version of IIWC/FEA/CUB's DCF is examined. (IIWC/FEA/CUB Ex. 1.0 Appx. B at 36, 44.) Similarly, Mr. Moul performed a risk premium analysis that produced an 11.25% return, well above his DCF. (IAWC Ex. 1.0 at 4.) An alternative risk premium calculation based on information relied on by Mr. Gorman shows a return of 10.14%, which is also greater than any DCF recommendation. (IAWC Ex. 10.00R at 26-27.) There is no question that the DCF results are uniformly lower than other methods.

Thus, the record establishes that the Staff DCF results presented to the Commission plainly do not reflect investor requirements. Worse, the DCF results artificially depress the parties' recommendations when averaged with the results of the CAPM and other methods.

Some of IIWC/FEA/CUB's DCF results are equally suspect. In fact, a meaningful portion of the DCF results presented by Mr. Gorman are unreasonable on their face. As indicated below, several of Mr. Gorman's DCF results fall into that category:

COMPANY	DCF
Middlesex Water	5.38%
American States Water	6.08%
York Water	7.17%
Connecticut Water	7.61%

(IAWC Ex. 10.00R at 23.)

Yet, as Mr. Moul explained, each of the companies listed above have DCF returns calculated by Mr. Gorman that fail to provide a sufficient spread over the average yield of 4.09% on A-rated public utility bonds and 5.03% on Baa-rated public utility bonds. (IAWC Ex. 10.00R at 23; *see also* IIWC/FEA/CUB Ex. 1.0 Appx. B, Sch. 1.9 at 1.)

These demonstrated anomalies have led the FERC to re-evaluate its approach to establishing DCF-based equity returns for entities under its jurisdiction. *See Order 531*, 147 FERC 61,234. As an institution of considerable technical skill and prestige, FERC's conclusions deserve attention. Indeed, IIWC/FEA/CUB used the two-stage FERC model in estimating a return on the market to derive a CAPM market risk premium. (IIWC/FEA/CUB Ex. 1.0 Appx. B at 43-44.) If the FERC approach was reliable for this purpose, it is equally reliable for others.

Order 531 arose from a complaint challenging a group of transmission owners' rates. "The Complainants argued that the bubble in the U.S. housing market, the subsequent financial crisis and economic recession, and the fiscal and monetary policies of the U.S. government have caused a 'flight to quality' in the capital markets. The Complainants contended that these market conditions have lowered bond yields and, as a result, capital costs for utilities." *Order 531*, 147 FERC 16,234 at ¶ 3.

FERC disagreed. FERC concluded that "the capital market conditions since the 2008 market collapse and the record in this proceeding have shown that there is not a direct correlation between changes in U.S. Treasury bond yields and changes in ROE." *Id*. at ¶ 158. This finding led FERC to not only change its DCF methodology, but to also abandon its long-standing policy of post-hearing adjustments to ROE for changes in U.S. Treasury yields. *Id*. at ¶ 160. "[A]djusting ROEs based on changes in U.S. Treasury bond yields may not produce a rational result, as both the magnitude and direction of the correlation may be inaccurate." *Id*. at ¶ 159.

FERC emphasized that ROE serves both a compensatory and capital attraction function. While a "mechanical application" of the DCF produced a midpoint of 9.38% based on the record in *Order 531*, a reduction to that level (from 11.4%) "could undermine the ability of the [utilities] to attract capital for new investment" and impose a "competitive disadvantage" relative to other utilities. *Id*. at ¶ 150.

The FERC DCF relies on publicly available sources for both stages of the growth rate. The initial five-year stage is based on analysts' five year forecasts. "[E]arnings forecasts made by investment analysts are considered to be the best available estimates of short-term dividend growth because they are likely relied on by investors when making their investment decisions." *Id.* at ¶ 17. Staff and IIWC/FEA/CUB performed their multistage DCF calculations with growth rates from the same sources. The long-term growth rate component of the FERC calculation is based on forecasted GDP growth. *Id*. at ¶ 20. Staff and IIWC/FEA/CUB use GDP as a proxy for their long term growth rate as well. (ICC Staff Ex. 5 at 9-11; IIWC/FEA/CUB Ex. 1.0 Appx. B at 26.)

FERC, however, does not give these growth rates equal weight. "The short-term forecast receives a two-thirds weighting and the long-term forecast receives a one-third weighting in calculating the growth rate in the DCF model." *Id*. at ¶ 17. The weighting scheme recognizes that "long-term projections are inherently more difficult to make, and thus less reliable, than short-term projections." *Id*. at ¶ 21 *quoting In re Transcon. Gas Pipeline Corp.*, 84 FERC 61,084 at 61,423-24 (July 29, 1998). *See also Canadian Assoc. Petroleum Producers v. FERC*, 254 F.3d 289, 297 (D.C. Cir. 2001) (affirming weighting scheme for growth rates).

If Staff's variables for growth rates are plugged into the FERC two-stage DCF model, the implied investor required return is 10.51%, based on the midpoint of the upper half of a range of 8.02% to 12.99%.[11] The calculation is the result of simple mathematics, using the established DCF formula, and variables for this formula that are also part of the record. And 10.51% fits comfortably within the range of results indicated by Mr. Moul. The Commission is therefore entitled to give this information the weight it believes it deserves. "Just as each case needs to be judged on its own merits, the decision regarding which version of the DCF model is most suitable depends on the facts and circumstances at the time of the particular analysis." (ICC Staff Ex. 13.00 at 11.)

FERC recognized that the DCF midpoint results fell below state authorized ROEs for electric distribution utilities. "Although we are not using state commission-approved ROEs to establish the [utilities'] ROE in this proceeding, the discrepancy between state ROEs . . . serves

[11] Staff's DCF model is described in Exhibit 5.0, Schedule 5.01. The sample companies and growth rates are shown in Schedule 5.02. When the growth rates in Schedule 5.02 are replaced with analysts' short-term growth rates and Staff's projected growth in GDP (weighted 2/3 and 1/3, respectively), the range of returns shown on Staff's Schedule 5.05 would change to the range indicated.

as an indicator that an upward adjustment to the midpoint here is necessary to satisfy *Hope* and *Bluefield*." *Id*. at ¶ 148.

Here, as in *Order 531*, the DCF-implied results are consistently lower than other models. "[T]he risk premium analysis, the CAPM, and expected earnings analyses . . . each produces a midpoint (or median) ROE higher than the midpoint of our DCF analysis here." *Id*. at ¶ 146. Here, as in *Order 531*, the DCF-implied results are far below any benchmark the Commission might use—the Company's current ROE, the average ROE of its affiliates, the ROE authorized for Aqua Illinois; it does not matter. The implied DCF result are lower than all available benchmarks. And here, as in *Order 531*, the record of anomalous capital markets abound, including well-informed judgment that future interest rates have only one direction to move—up. "[T]he nationally renowned bond investor Bill Gross commented that global bond yields were the lowest 'in 500 years of record history' and warned that the large number of negative-yielding bonds in the world will eventually lead to 'a supernova that will explode one day.'" (IAWC Ex. 10.00R at 13-14.)

Rather than simply take the DCF-implied returns at face value, the Commission should take into account the evidence regarding low interest rates, how those interest rates depressed the ROE midpoint, and how interest rates will rise in the near-term. *See Order 531* at ¶ 130. Moreover, because the DCF analysis is meant to reflect the rate of return needed to attract investors going forward, data showing increasing interest rates and cost of capital are particularly relevant. *Id*.

e. Mr. Moul's DCF results are more reliable than Staff's or IIWC/FEA/CUB's.

Although the Staff and FERC application of the DCF are both multi-stage models (with FERC using two growth stages and Staff using three), the disparity in results is explainable by the assumed rates of growth and their weighting. Like the FERC model, Staff uses analysts' five-year forecasts for initial stage growth and GDP for final stage growth. (ICC Staff Exhibit 5.0 at 7-9.) But Staff adds an intermediate growth stage represented by the average of the first and third stage growth rates, and gives each of the three stages equal weighting. (*Id.* at 9.) The intermediate growth stage is a mathematical calculation untied to any evidence that investors rely on growth rates calculated this way when making investment decisions. (*See* IAWC Ex. 10.00R at 25.) And as FERC observed, long-term growth rates are by nature more difficult to predict. *Order 531*, 147 FERC 16,234 at ¶ 21. FERC's approach of weighting short-term projections more heavily than long term projections is consistent with the growth rate evidence produced here. As Mr. Moul explained, earnings growth for the comparable companies historically ranged from 6.36% to 8%, and in the future is projected at 6%. (IAWC Ex. 10.00 (Rev.) at 22-23.) Staff's second-stage growth rate of 4.2% is demonstrably too low.[12]

Mr. Moul's DCF estimates the cost of equity at 9.89%, based on single-stage growth of 6.25% and inclusive of a "leverage" adjustment. (IAWC Ex. 10.00 (Rev.) at 31-32.) Although Mr. Moul's approach is different than FERC's, the similarity of results confirms that both approaches represent different methods of arriving at similar results for the investor-required ROE.

With regard to growth rates, Mr. Moul generally disfavors a multi-stage DCF model because, as FERC recognized, there is no recognized source for analysts' long-term growth

---

[12] "Staff used the forecasted GDP growth of the United States economy as a proxy for the long-term growth in dividends per share paid to the investors of the sample groups….accepting that long-term GDP growth will be 4.2% merely establishes that *the economy as a whole* will, on average, grow 4.2% annually. That does not mean that stock prices will grow at that rate. Stock market prices do not play a key role directly in the measurement of the GDP. Some companies and industries will grow faster than the average, some slower." (IAWC Ex. 10.00R at 7-9.)

expectations. (IAWC Ex. 10.00R at 8.) Mr. Moul approaches this limitation by employing a single-stage DCF. (IAWC Ex. 10.00 (Rev.) at 21.) The FERC two-stage model approaches this limitation by giving analysts' short-term growth rate projections more weight than long-term projections. *Order 531*, 147 FERC 16,234 at ¶ 17. Both methods address the same limitation presented by speculating about investors' long-term growth projections.

A leverage adjustment to the DCF is necessary to make an apples-to-apples comparison of the returns calculated for the comparable companies to the investor-required return of IAWC. The DCF model pre-supposes that the indicated return is the cost of equity for a firm with its market value, weighted cost of capital. (*See* IAWC Ex. 10.00 (Rev.) at 28-29.) The average capital structure of the Water Group consists of 31.71% debt and 68.22% equity (*id*. at 26), while the ratio for IAWC is closer to 50/50. (*See* IAWC Ex. 6.01SR.) The introduction of additional debt in the capital structure increases risk. (IAWC Ex. 10.00 (Rev.) at 28.) The leverage adjustment is needed to account for the fact that IAWC has more debt in its capital structure than the comparable companies, and is therefore subject to more risk. (IAWC Ex. 10.00 (Rev.) at 27-29.)

The FERC two-stage DCF does not contain an express leverage component, but the FERC approach in general focuses on the goal of capital attraction in light of investor requirements. *Order 531*, 147 FERC 16,234 at ¶ 50. "The only perspective that is important to investors is the return they can realize on the market value of their investment." (IAWC Ex. 10.00 (Rev.) at 27.) An adjustment to account for the difference in book value to market value is entirely consistent with the notion that the DCF ought to be applied in a manner that best explains investor expectations.

Staff will criticize any leverage adjustment, but not for reasons having anything to do with investor requirements. Indeed, investors are an afterthought to Staff's recommendation. Staff's analysis attempts to predict the Water Group's required returns, without bothering to look at their current, authorized returns. (IAWC-Staff Stip. Cross Ex. 1.0 at 5.) Staff did not compare its recommendation to that of any other state regulatory commission. (*Id*. at 8.) Indeed, according to Staff, any recommendations by this or any other commission in the past 24 months are not relevant. (*Id*. at 9, 10.) Asked how investors would be expected to react to Staff's recommendation, Staff has "no opinion." (*Id.* at 6.) This indifference to investor requirements is telling.

Mr. Moul's are the only DCF results remotely in the range of the 10.51% indicated by the FERC two-stage DCF model. The average of Mr. Moul's DCF and CAPM results is 10.41%—remarkably close to what the ROE would be if the issue were in front of FERC. Mr. Moul's 10.75% recommendation is also validated by his risk premium analysis showing a required return of 11.25% and a comparable earnings analysis suggesting a return as high as 13.05%. (*See* IAWC Ex. 10.00 at 32, 46.) Neither Staff nor IIWC/FEA/CUB can point to any extrinsic evidence supporting the reasonableness of their proposals.

f. A Rider VBA reduction would be asymmetrical and unwarranted.

Staff's claim that approval of Rider VBA should be accompanied by a reduction in ROE should be rejected. (*See* ICC Staff Ex. 13.0 at 3.) Staff has never proposed an upward adjustment to account for the likelihood of a utility not earning its authorized return. A mechanism that serves only to allow a utility to earn the ROE the ratemaking process assumes (often erroneously) the utility will earn is not grounds for a downward ROE adjustment of any amount.

Staff claims that Rider VBA would reduce volatility in IAWC's cash flows and improve its credit rating, thereby decreasing risk and lowering investors' required ROE. (ICC Staff Ex. 5.0 at 35, 37.) This argument ignores the fact that the Company's cost of equity is being determined with reference to a proxy group of similar utilities. Mr. Moul explained that the recommended ROE should not be reduced downward to account for the impact of Rider VBA on the Company's business risks because the market-derived ROE for the Company is estimated from market information on the cost of common equity for other comparable water utilities. (IAWC Ex. 10.00R at 19.) Because it has become increasingly common for utility companies in the water, electric, and natural gas industries to employ alternative rate design and ratemaking mechanisms, the approval of trackers, riders and adjustment clauses, forecast test years, and other mechanisms, by regulatory commissions is widespread in the utility business and is already largely embedded in financial data, such as bond ratings, stock prices, and business risk scores. (*Id.*) To the extent that the market-derived cost of common equity for other utility companies already incorporates the impacts of these or similar mechanisms, no further adjustment is appropriate or reasonable in determining the cost of common equity for the Company. To do so would constitute double-counting.[13] (*Id.*)

In fact, five of the nine companies in the Water Group utilize alternative ratemaking mechanisms. (*Id.* at 20; *see also* IAWC Ex. 10.02, Sch. 3 at 2.) Thus, the existence, approval, and impact of these alternative ratemaking mechanisms is embedded in the data the parties used to develop their ROE analyses, including the stock prices, bond ratings, and business risk scores.

---

[13] Staff drew this conclusion by considering Rider VBA in isolation, without considering the overall impact of Staff's proposal to reduce IAWC's authorized ROE to an unprecedentedly low level. (ICC Staff Ex. 13.00 at 26; IAWC Ex. 10.00R at 18.) As Mr. Moul explained, Staff's proposal would result in the lowest ROE the Commission has authorized since it started keeping public records on the subject, the lowest authorized ROE in the RRA data, and the lowest ROE authorized for any American Water utility. (IAWC Ex. 10.00R at 19-20.) Such a large and unprecedented reduction in authorized ROE would certainly not lead to a credit upgrade, *even if* Rider VBA reduced volatility in the Company's cash flows.

(IAWC Ex. 10.00R at 21.) As a result, the existence, approval, and impact of the alternative ratemaking mechanisms is embedded in the results of those analyses. Mr. Moul's position is well-supported by empirical studies. The Brattle Group published a study in March 2011 entitled "The Impact of Decoupling on the Cost of Capital: An Empirical Investigation." (*See id*. at 21-22.) The study concluded that any impact from decoupling on the cost of capital "must be minimal because it is not detectable statistically." (IAWC Ex. 10.07R.) The Brattle Group released a similar study on March 20, 2014 entitled "The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation." (IAWC Ex. 10.00R at 21-22.) The findings of this study were similar to those of their 2011 study, concluding that "there is no statistically significant evidence of a decrease in the cost of capital following adoption of decoupling." (IAWC Ex. 10.00R at 21-22.)

There are simply no grounds for Staff's Rider VBA deduction.

g. A just and reasonable ROE is necessary to support investment, attract capital, and position IAWC to meet the challenges of the future

In the oft-cited *Hope* decision, the United States Supreme Court stated:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Fed. Power Comm'n v. Hope Nat. Gas Co., 320 U.S. 591, 603 (1944) (citations omitted). This important statement is a recognition that capital cannot be conscripted and that it will flow to where it obtains the best return for commensurate risk.

The Company's President, Mr. Hauk, explained how IAWC must compete for capital, not only with other enterprises, but with other American Water affiliates. The collective needs of the American Water utilities exceed available capital. (IAWC Ex. 1.00R at 4.) Capital needs for maintaining service quality and reliability in accordance with laws and regulations always get top priority. (*Id*. at 5.) The shareholder is committed to investing in projects necessary to maintain safe and adequate service. (*See id*. at 5.) But the shareholder has the opportunity to invest in many discretionary projects, and available returns influence the shareholder's decision of where to invest discretionary funds. (*Id*. at 5-6.) It does not make sense for the shareholder to invest discretionary capital in Illinois if greater returns are available in other states. (*Id*. at 5.)

IAWC currently has the lowest authorized ROE of any utility in the American Water system. This does not mean the water and sewer system in Illinois is facing a critical risk of falling apart. It does mean, however, that IAWC is at the bottom of the pecking order for discretionary capital. This is not a sustainable situation in the long term if the Commission expects IAWC to continue to deliver exceptional service, as we detail below.

The need for discretionary capital is real. The Company explained the confluence of factors contributing to the need to address aging water infrastructure in a more pro-active, accelerated fashion. (IAWC Ex. 1.00R at 7; *see also* IAWC Ex. 3.00R at 2-10.) This need exists throughout the United States. The subsidiaries with competitive rates of return are much more likely to attract the capital necessary to address these needs proactively. (IAWC Ex. 1.00R at 7-8.) Less competitive subsidiaries (like IAWC) will have to settle for what is needed to address these issues reactively. (*Id*. at 8.)

American Water's customers in Illinois have been provided with exceptional service. If the Company is to continue to provide such exceptional service and efficient operations, it must be provided with the continued means to do so. Mr. Hauk's description of the struggle to obtain discretionary capital is real and has real implications for IAWC's customers. The Commission should provide Mr. Hauk and his team with the tools to obtain the levels of funding necessary to allow them to continue doing the exemplary job they've been doing.

h. The authorized ROE should reflect the Company's exceptional performance and its dedicated commitment to providing its Illinois customers with exceptional service at high levels of operational efficiency.

It is a long-established element of regulation that the cost of equity falls within a range of reasonableness and that this Commission has discretion to determine, where, within that range, a given utility's authorized rate of return on equity should fall. It is an equally long-established truism of regulation that more efficient utilities should be rewarded with higher earnings while less efficient and imprudent utilities should see reduced earnings. Although this Commission has recognized that efficient operations are the norm and do not entitle the utility to premium returns,[14] this does not mean that a utility company should not be rewarded for truly excellent and exemplary results with a rate of return on equity in the higher end of the zone of reasonableness. IAWC believes that the record establishes that this is a case where a return at the higher end of the zone of reasonableness is more than warranted.

The Company is proud of its achievements since the last rate case in the areas of service quality and reliability, and is committed to carrying these successes forward into the future. First, this is the Company's first rate case in the last five years. This is an impressive record of rate stability and a testimonial to the efficiency of the Company's operations. In fact, in the five

---

[14]"[E]fficient service is the objective of all utilities and a legal requirement under Section 8-401 of the Act, and no special reward needs to be offered." *Ill. Commerce Comm'n on Its Own Motion v. N. Ill. Gas Co.*, Docket 87-0032, 1988 WL 1533285 (Jan. 20, 1988).

years since the Company's last case, IAWC has *reduced* O&M expenses below the amount authorized by the Commission in the last rate case. (IAWC Ex. 1.00 (Rev.) at 11.) That is virtually unheard of for a regulated utility.

Moreover, and notwithstanding that the Company has reduced its expenses, service has not suffered as a result. Indeed, IAWC has achieved quite the opposite: a recent J.D. Power survey gave IAWC top honors for customer satisfaction:

(*See* IAWC Ex. 1.00R at 8.)

Not only has the Company excelled in containing and reducing costs and in providing the highest levels of service but IAWC is also a leader in promoting a diverse workforce. (IAWC Ex. 1.00 (Rev.) at 19-21.) Just under 70 percent of the people IAWC hired in 2015 are diverse, and the Company tripled its spend with diversified suppliers in 2015 versus 2014. (IAWC Ex. 1.00R at 8.)[15] Over 85% of the requested rate increase is driven by plant investment (IAWC Ex. 1.00 (Rev.) at 10), yet no rate base disallowances have been proposed in this case. No affiliate transaction issues have been raised. In short, not only does IAWC not deserve the punitive ROE that Staff and IIWC/FEA/CUB recommend in this case but a rate of return in the upper end of the zone of reasonableness is fully warranted for the achievements that the Company has produced.

A 10.75% ROE is just, reasonable and appropriate.

B. Resolved Issues

1. Capital Structure

The parties agree that the following average test year capital structure is reasonable for setting rates in this proceeding:

CAPITAL COMPONENT	BALANCE	WEIGHT
Short-term Debt	$17,060,924	1.90%
Long-term Debt	$433,176,118	48.30%
Common Equity	$446,559,694	49.80%
Total	$896,796,736	100.00%

(ICC Staff Ex. 12.0 at 2, Sch. 12.01; IAWC Exs. 6.00SR at 2 (accepting, to narrow the issues in this proceeding, Staff's proposed common equity ratio), 6.01SR; IAWC-IIWC/FEA/CUB Stip. Cross Ex. 1.00 at 4; AG Exs. 3.0 at 3, 3.1 at Sch. A-3 (relying on Staff's proposed capital ratios).) In light of the parties' agreement, the Commission should approve this capital structure.

[15] The Company is a founding member of the Illinois Utilities Business Diversity Council (IUBDC), formed by the members of the Illinois Energy Association. The IUBDC is a forum for best practice sharing and information exchange among Illinois' utilities, with a focus on advancing the growth and utilization of diverse businesses in the state of Illinois. IAWC hosts and participates in diversity events in Illinois. IAWC supports the National Minority Supplier Development Council (NMSC), the Women's Business Enterprise National Council (WBENC), the Women in Energy Chicago Chapter, the Black Business Alliance (WPNV 106.3 FM Radio Peoria), and the Illinois Black Chamber of Commerce. IAWC also participates in American Water's investment diversity initiatives. (IAWC Exhibit 1.00 (Rev.) at 21.)

2. Cost of Debt

The parties agree that 0.74% and 5.34% are reasonable average costs of short-term debt and long-term debt, respectively, for IAWC in the test year. (IAWC Exs. 6.00R at 3-6, 7-8, 6.01R; ICC Staff Ex. 12.0 at 3-4, Sch. 12.01; IAWC-IIWC/FEA/CUB Stip. Cross Ex. 1.00 at 4; AG Ex. 3.1 at Sch. A-3.) In light of the parties' agreement, the Commission should approve these costs of short-term and long-term debt.

C. Recommended Capital Structure and Rate of Return

For the reasons explained, IAWC proposes the following average capital structure, costs of debt and equity, and overall weighted cost of capital for setting rates in this proceeding:

CAPITAL COMPONENT	WEIGHT	COST	WEIGHTED COST
Short-term Debt	1.90%	0.74%	0.01%
Long-term Debt	48.30%	5.34%	2.58%
Common Equity	49.80%	10.75%	5.35%
Total	100.00%		**7.94%**

(IAWC Exs. 6.00SR at 1, 6.01SR.)

III. RATE BASE

A. Contested Issues

1. Accumulated Deferred Income Taxes Balance / FIN 48

FASB[16] Interpretation Number 48, or FIN 48, now codified as part of Accounting Standards Codification 740, is FASB's financial accounting guidance related to uncertain tax positions. FIN 48 prescribes the way in which companies must analyze, quantify, and disclose the most probable outcome that will result from taking a tax position that is uncertain. (IAWC Ex. 13.00R at 7.)

[16] Financial Accounting Standards Board

IAWC has concluded that some of the tax positions that are part of its method of accounting for repairs are uncertain, and it quantified FIN 48 balances accordingly. (*Id*. at 8.) AG witness Effron argued that IAWC has realized tax savings from taking the repairs deduction on its tax returns. (AG Ex. 1.0 at 9.) Until these deferred tax liabilities are actually paid to the relevant taxing authorities, he contended, they represent non-investor supplied funds that are available to the Company. He proposed the ADIT debit balances related to FIN 48 should be eliminated from the balance of ADIT deducted from plant in service, increasing ADIT and thus reducing rate base. (*Id*. at 10.)

IAWC is willing to eliminate an adjusted FIN 48 balance from rate base. However, Mr. Effron's adjustment must be revised in two ways. First, the ADIT balance in rate base related to FIN 48 is $3,432,525, not $18,343,822, as Mr. Effron proposed. $3,432,525 is the net FIN 48 amount after considering offsets by available net operating losses. This net number is what is included in ADIT. (IAWC Ex. 13.00SR (Rev.) at 2.)

Second, changes in IAWC's proposed 2015 tax filings will cause a portion of the uncertain tax positions to be realized. Therefore, with respect to a 2017 test year, a portion of the deferred tax liability associated with uncertain tax positions will have been eliminated when IAWC files its 2015 tax return. (IAWC Ex. 13.00R at 8-9.) The adjustment to prior repair deductions has been computed, and the change results in IAWC realizing $909,707 of its FIN 48 obligation, reducing the amount of the ADIT impact on rate base from $3,432,525 to $2,485,188. (IAWC Ex. 13.00SR (Rev.) at 2.)

Mr. Effron also proposed that IAWC provide a method for the Commission to verify that the revised FIN 48 amounts are consistent with the filed 2015 tax return. (AG Ex. 3.0 at 5.) This is not necessary: all ADIT activity estimated by the Company through the 2017 test year has not as yet been reflected on a filed tax return. That fact is inherent in using projections and basing rates on a forecasted test year. And IAWC should not be required to document tax positions that IAWC plans to take with respect to repairs in its 2015 tax return in a manner different than it documents any other tax projection. If the Commission desires, however, IAWC is willing to provide a confidential disclosure of IRS Form 3115 (Application for Change in Accounting Method) or a copy of IAWC's federal pro forma 2015 tax return as a compliance filing in this docket. (IAWC Ex. 13.00SR (Rev.) at 3-4.)

2. Debt Return on Pension Asset

The Company has agreed to reflect in rate base a $1,898,284 accrued liability for other (non-pension) post-employment benefits (OPEBs), which represents the cumulative excess of accrued OPEB costs over actual cash disbursements for OPEB. (IAWC 4.00R at 15; AG Ex. 1.0 at 7.) This has the effect of reducing rate base.

However, IAWC also has a pension asset in the amount of $6,760,144, which reflects the difference between accrued pension expense and projected cash pension contributions. (*See* Schedule B-9.1, Schedule G-5 at 10.) When the accrual for pension expense collected from ratepayers exceeds the contribution amounts, the Commission consistently approves a reduction in rate base reflecting the difference. *See, e.g., Ill.-Am. Water Co*., Docket 09-0319, Order, Appx. A at 2 (Apr. 13, 2010); *Ill.-Am. Water Co*., Docket 07-0507, Order, Appx. A at 3 (July 30, 2008); *Ill.-Am. Water Co.*, Docket 92-0116, Order, Appx. A (Feb. 9, 1993). *See also Aqua Ill., Inc.*, Order, Docket 04-0442, Order, Appx. at 5 (Apr. 20, 2005); *Consumers Ill. Water Co.*, Docket 03-0403, Order, Appx. A, Sch. 3 (Apr. 13, 2004); *Cent. Ill. Light Co.*, Dockets 01-0465/0530/0637 (cons.), Order, Appx. A, Sch. 3 (Mar. 28, 2002); *Consumers Ill. Water Co.*, Dockets 00-0337/0338/0339 (cons.), Order, Appx. B-K (Jan. 31, 2001).

IAWC recognizes that the reverse is not true—when pension contributions exceed the pension expense amount IAWC collects through rates, as is projected to occur in this case, the Commission has not approved an increase to rate base. *Ill.-Am. Water Co.*, Docket 11-0767, Order at 8 (Sept. 19, 2012). However, it remains IAWC's position that including only pension and OPEB balance sheet liabilities, but not the assets, in rate base is inconsistent. (IAWC 4.00R at 15-16.) IAWC therefore proposes a middle ground approach, under which IAWC receives a debt return for its pension asset. This is not an unprecedented proposal: the Commission has previously approved a debt return on certain pension contributions for Commonwealth Edison. *Commonwealth Edison Co.*, Docket 05-0597, Order on Reh'g at 28 (Dec. 20, 2006). And the Illinois formula rate law also allows a debt return on all pension assets. 220 ILCS 5/16-108.5(c)(4)(D). IAWC therefore considers a debt return on its pension asset a reasonable way to balance the deduction of the OPEB liability from rate base. As shown on IAWC Exhibit 4.07SR, such a return would increase the revenue requirement by approximately $175,000.

3. Cash Working Capital for Deferred Income Tax

Cash working capital is the amount of funds necessary to finance the day-to-day operations of a utility. (IAWC Ex. 12.00 at 2.) The necessary level of cash working capital is determined using a lead-lag study, which determines the timing of cash inflows and outflows. (IAWC Ex. 12.00 at 3.)

The two primary components of a lead-lag study are revenue lags and expense leads. (*Id.* at 3.) The revenue lag represents the period of elapsed time between when a company delivers its product to its customers, and when it receives payment from them. (*Id.*) The expense lead represents the period of elapsed time between when a good or service is provided to the company, and when the company pays its supplier for that good or service. (*Id.*) The revenue lag is compared against the expense lead, and the net difference is the company's cash working capital requirement. (*Id.*)

A dispute arose in this case regarding the cash working capital requirement associated with deferred income taxes. Deferred income taxes are generally deducted from rate base because they are considered a cost-free source of funds. (IAWC Ex. 12.00 at 13; IIWC/FEA/CUB Ex. 2.0 (Rev.) at 36.) In this case, the Company deducted deferred income tax amounts from rate base. (IAWC Ex. 12.00 at 13.) The Company also assigned a zero-day expense lead to deferred income taxes in the lead-lag study to reflect the fact that there is no current expense associated with the deferred tax amounts. (IAWC Ex. 12.00SR at 2.)

The Company, however, applied the same revenue lag it applies to all other revenues to the deferred tax amounts. (IAWC Ex. 12.00 at 13.) Application of the revenue lag reflects the reality that IAWC collects the dollars associated with its deferred tax liability in the same way that it collects *all other revenues*—by billing and collecting from its customers. (IAWC Ex. 12.00SR at 2-3.) All IAWC's revenues are subject to a 49.3-day revenue lag, on average. (IAWC Ex. 12.00R at 5.)

Staff did not dispute IAWC's method of calculating cash working capital associated with deferred income taxes. (ICC Staff Ex. 10.0 at 3.) However, IIWC/FEA/CUB witness Gorman proposed to eliminate the revenue lag applied to deferred tax amounts—in other words, apply a zero-day revenue lag. (IIWC/FEA/CUB Ex. 1.0 at 16-17.) Mr. Gorman made three arguments in support of his proposal, but none of these arguments withstands scrutiny, and his proposal should be rejected.

First, Mr. Gorman argued that a zero-day revenue lag was appropriate because "cash received by IAWC in rates for deferred income taxes is not currently paid." (IIWC/FEA/CUB

Ex. 1.0 at 16:301-02.) He stated that "[e]xpenses such as deferred income tax are recorded … but do not reflect any payment to a vendor or third party." (IIWC/FEA/CUB Ex. 2.0 (Rev.) at 36:667-69.) It is clear from these statements that Mr. Gorman has confused the components of the lead-lag study. As discussed above, there are two components of cash working capital: the revenue lag, and the expense lead. Mr. Gorman's proposal is to modify the *revenue lag*, yet his argument focused on when or whether IAWC incurs an *expense* for deferred income taxes. IAWC's lead-lag analysis *already* accounted for the fact that there is no current expense associated with deferred income taxes by applying a zero-day expense lead. (IAWC Ex. 12.00SR at 3.) IAWC also accounted for this by subtracting the deferred taxes from rate base. (*Id.*) Given Mr. Gorman's confusion on this issue, his testimony provides no support for his proposed adjustment.

Second, Mr. Gorman argues that a zero-day revenue lag should be applied to deferred income taxes because the taxes are "a cost-free source of cash." (IIWC/FEA/CUB Ex. 1.0 at 16:309.) But the fact that deferred income taxes are a cost-free cash item has been accounted-for outside of the cash working capital analysis because IAWC subtracted the deferred taxes from rate base. (IAWC Ex. 12.00SR at 3.) For purposes of determining the appropriate revenue lag in the cash working capital analysis, the relevant inquiry is when the Company collects cash from its ratepayers. (*Id.*) Deferred tax amounts cannot become a "cost-free source of cash" to the Company until the Company actually collects the cash amounts from its customers. (*Id.*)

Third, Mr. Gorman argues that the deferred income taxes should be considered equivalent to depreciation and uncollectibles expenses, which are assigned a zero-day revenue lag. (IIWC/FEA/CUB Ex. 1.0 at 16-17.) But IAWC's calculation of cash working capital for depreciation, uncollectibles, and deferred tax expense is consistent with past Commission findings in IAWC cases. (IAWC Ex. 12.00SR at 4.) Mr. Gorman has presented no compelling reason to depart from Commission practice. His proposal should be rejected.

B. Resolved Issues

1. Accrued Liability for OPEB

The Company has agreed to reflect in rate base an $1,898,284 accrued liability for other (non-pension) post-employment benefits (OPEBs), which represents the cumulative excess of accrued OPEB costs over actual cash disbursements for OPEB. (IAWC 4.00R at 15; AG Ex. 1.0 at 7.)

2. Capitalized Prior Performance Plan Costs

AG witness Effron proposed to remove the capitalized costs of incentive compensation plans that were not included in the revenue requirement in IAWC's last rate case, Docket 11-0767. (AG Ex. 1.0 at 10.) Mr. Effron's adjustment removed the costs of these plans that were capitalized from 2012 through 2016. (AG Ex. 1.0 at 10.) The Company accepted the portion of this adjustment that removed previously disallowed capitalized incentive compensation costs. (IAWC Ex. 4.00R at 16.) Mr. Effron made additional corrections to the calculation as agreed upon in discovery. (AG Ex. 3.0 at 6.) Therefore, the Company considers this issue resolved.

3. Cash Working Capital

a. Income Available for Return on Equity in Cash Working Capital

IIWC/FEA/CUB witness Gorman proposed a correction to the amount of income available for common equity included in cash working capital. (IIWC/FEA/CUB Ex. 1.0 at 16.) The Company accepted Mr. Gorman's correction, and considers this issue resolved. (IAWC Ex. 12.00R at 3.)

b. Tank Painting Amortization

Staff witness Hathhorn and IIWC/FEA/CUB witness Gorman proposed corrections to exclude tank painting amortization from the cash working capital calculations of depreciation and amortization expense and from maintenance-other expense. (ICC Staff Ex. 2.0 at 4; IIWC/FEA/CUB Ex. 1.0 at 17.) IAWC accepted Staff's corrections in discovery, (*see* ICC Staff Ex. 2.0 at 4), and IIWC/FEA/CUB acknowledged that these corrections resolved their concerns. (IAWC Ex. 12.00R at 3-4.) Therefore, this issue is resolved.

c. Rate Case Expense Amortization

IIWC/FEA/CUB witness Gorman proposed a correction to remove rate case expense amortization from the cash working capital calculation. (IIWC/FEA/CUB Ex. 1.0 at 17.) IAWC accepted this correction in discovery. (*See* IAWC Ex. 12.00R at 3-4.) Therefore, this issue is resolved.

4. Accumulated Deferred Income Taxes

a. Deferred Tax Assets for UPAA and Deferred Rate Proceedings

Staff witness Hathhorn proposed to adjust rate base to exclude accumulated deferred income taxes for two accounts that the Company acknowledged it inadvertently included in each rate zone. Accounts for Net UPAA (utility plant acquisition adjustment) and Deferred Rate Proceedings should not have been included in the deferred tax calculation as the associated assets and liabilities are not included in rate base. (ICC Staff Ex. 2.00 at 5.) IAWC agreed to these adjustments. (IAWC Ex. 4.00R at 3.)

b. Restated for Change in State Income Tax Rate

Staff witness Hathhorn and AG witness Effron both accepted IAWC's proposal to use the 7.75% state income tax rate, which is based on a 100% apportionment factor reflecting IAWC's activities in Illinois, rather than on a five-year average estimate of American Water Company's apportionment factor. (ICC Staff Ex. 10.0 at 4; AG Ex. 3.0 at 2.) Mr. Effron and Ms. Hathhorn accordingly proposed to reflect the Company's state and federal ADIT balances at the 7.75% state income tax rate. (ICC Staff Ex. 10.0 at 4; AG Ex. 3.0 at 6-7.) IAWC accepted these adjustments. (IAWC Ex. 4.00SR at 4, 10.)

5. Deferred Charges related to Cairo Filter Project

In discovery, IAWC agreed to an adjustment to reduce rate base by $2,162,500 to correct the balance of deferred charges on Schedule B-10 for two filter projects in Cairo that should not be included as deferred maintenance. (IAWC Ex. 4.00R at 4.) Staff and AG witnesses acknowledged this adjustment in testimony. (*See* AG Ex. 1.0 at 10; ICC Staff Ex. 2.0 at 4.) Therefore, this issue is resolved.

6. Accumulated Depreciation Correction

Staff witness Hathhorn proposed adjustments to the Company's accumulated depreciation correction, "adjust[ing] rate base downward to include accumulated depreciation for two accounts" inadvertently omitted by the Company from each rate zone, as well as corrections to Rate Zone 1 for accumulated amortization and depreciation and amortization expense. (ICC Staff Ex. 2.0 at 4-5: 90-94.) IAWC accepted these proposed adjustments. (IAWC Ex. 4.00R at 3.) Therefore, this issue is resolved.

C. Original Cost Determination

IAWC accepts Staff's recommendation "that the Commission conclude and make a finding in the Final Order in this proceeding that the Company's September 30, 2015 plant balance of $1,570,415,946 as reflected on Company's WPB 5a, be approved for purposes of an original cost determination, subject to any adjustments ordered by the Commission in this proceeding." (ICC Staff Ex. 2.0 at 14:340-44; IAWC Ex. 4.00R at 5.)

D. Recommended Rate Base

IAWC's recommended Total Company test year rate base is $884,343,956, as shown on IAWC Exhibit 4.03SR (Rev.). The rate bases for each Rate Area are shown on pages 2-5 of IAWC Exhibit 4.03SR (Rev.).

IV. OPERATING EXPENSES AND REVENUES

A. Contested Issues

1. Payroll Expense

Productivity enhancements have allowed IAWC to reduce employee headcount since its 2011 rate case, saving $300,000 in test year payroll expense. Any further, artificial, reductions to employee headcount should be rejected.

IAWC employs people, and its employees need to be paid. Payroll expense is an ordinary and necessary cost of doing business that must be recovered in rates. *People ex rel. Madigan v. Ill. Commerce Comm'n,* 2011 IL App (1st) 100654, ¶ 49 (*citing Bus. & Prof'l People for Pub. Interest v. Ill. Commerce Comm'n*, 146 Ill. 2d 175, 247 (1991); *Villages of Milford v. Ill. Commerce Comm'n*, 20 Ill. 2d 556, 565, (1960)).

The Company's projected test year headcount is already less than in its 2011 rate case. Instead of recognizing this achievement for what it is, Staff, the AG, and IIWC/FEA/CUB proposed to impute an even greater reduction in employee headcount. These parties refused to acknowledge evidence establishing the soundness of test year staffing levels, which already includes a vacancy factor. They simply assumed that historical staffing trends will be repeated in the future. This assumption is wrong, and so are the proposed adjustments. Payroll expense should be established as forecasted by IAWC.

a. IAWC's payroll expense will enable IAWC to employ the staff necessary to meet service obligations.

IAWC's test year payroll expense reflects the staffing level that IAWC projects it will need to meet its water and sewer service obligations to customers in 2017—an average of approximately 470 full-time positions. That's an average of 482 average full-time positions (479 full-time permanent positions each month of the test year, and 13 full-time temporary summer positions, June through August), reduced by 2.5% (approximately twelve positions) to account for anticipated vacancies in the test year. (IAWC Exs. 2.00 at 18-19; 2.00R (2d Rev.) at 2, 3.) Notably, IAWC's current headcount of 442 and the 24 positions it is actively recruiting for—466 total positions—already approximate the 2017 test year projection of 470 average full-time positions.

The test year staffing projection is the result of IAWC's current staffing needs and its continuous focus on appropriate staffing levels. (IAWC Ex. 2.00 at 18.) When IAWC staffs its water and sewer operations, it reviews each vacant position for overall need and considers, among other things, whether the position should be transferred, modified, or even eliminated. And IAWC similarly evaluates new positions that it may need to meet changing regulatory requirements, optimize new technology, and most effectively serve customers. (*Id*. at 18-19.) IAWC's continuous focus on identifying appropriate staffing needs allows it to effectively control labor costs while maintaining the workforce necessary to meet its service obligations to Illinois customers. (IAWC Ex. 2.00R (2d Rev.) at 3-4.)

Employing this focus on appropriate staffing levels, as of June 2016, IAWC has been recruiting for or planning to add 24 full-time positions to its May 31, 2016 442-person staff—for a current staff of 466 full-time positions. (IAWC Ex. 2.00R (2d Rev.) at 2-3.) IAWC identified those 24 positions on IAWC Exhibit 2.01R, and explained why each one is essential to the core functions of IAWC's operations: construction, operation, and maintenance of IAWC's water distribution and wastewater collection systems, meter testing and repair, customer service, and management of the personnel who perform that critical work. (*Id*. at 3; IAWC Ex. 2.01R.)

IAWC, for example, has been recruiting a union-represented Field Services Technician in its Peoria service area, to fill a position vacant due to a retirement. This employee performs JULIE locates, b-box and valve inspections and maintenance, fire hydrant flushing inspections, and leak detection, and reads, tests, and installs water meters, among other customer service responsibilities. (IAWC Ex. 2.01R.) As another example, IAWC has also been recruiting a Water Quality and Environmental Compliance Supervisor in its Woodbridge service area, to fill a position again vacant due to a retirement. This employee manages personnel and operations to ensure that IAWC meets Clean Water Act requirements, among other water quality, environmental, and regulatory compliance-related duties. (*Id.*)

All of the positions on IAWC Exhibit 2.01R are critical to serving IAWC's customers. (IAWC Ex. 2.00R (2d Rev.) at 3.) Therefore, IAWC's President and Vice President of Operations have approved those positions. (*Id*. at 4.) Before the end of 2016, and into the 2017 test year, IAWC may need to recruit for additional, but currently unplanned, full-time positions as business circumstances dictate, to meet its service obligations to Illinois customers. (*Id*. at 3.)

b. IAWC's test year payroll expense and headcount already account for anticipated position vacancies.

IAWC's test year payroll expense also accounts for 12 anticipated position vacancies in the test year. (IAWC Ex. 2.00R (2d Rev.) at 2.) This is because, historically, IAWC has been unable to fill all of its full-time position needs, for several reasons. First, the utility workforce is aging and retiring; IAWC has lost employees due to attrition. (*Id*. at 5.) Second, it is difficult to attract new STEM-qualified (Science, Technology, Engineering, Mathematics) talent to the public utility industry, to fill vacancies left by retiring talent. (*Id*.) And IAWC has recently increased its focus on diversifying its workforce, with great success: in 2014 and 2015, the majority of IAWC's new hires identified with a minority population. This focus, however, means that there may be delays in filling open positions. (*Id*.)

So, while IAWC continuously strives to fill all open positions, it reasonably anticipates some vacancies in the test year. IAWC reduced its projected 482 average 2017 head count by 2.5%, or approximately 12 positions, to appropriately account for this. (*Id*.) This means that IAWC is already near its 2017 projected 470 average full-time position headcount, considering IAWC's May 2016 headcount and the positions IAWC has been recruiting for or is planning to hire in 2016.

c. IAWC's test year payroll expense and headcount are already reduced.

Notably, IAWC's test year staffing level in this case is 26 positions *less* than IAWC's approved staffing level in Docket 11-0767, including anticipated vacancies. This means that the payroll expense here is less, too—by over $300,000. (IAWC Ex. 2.00 at 19.)

The reduction is the result of IAWC's organizational streamlining efforts and technology initiatives, like its Advanced Meter Reading program, which has allowed IAWC to eliminate 16 full-time equivalent positions, and Business Transformation, American Water's system-wide deployment of new, integrated information technology systems to improve technological efficiencies, increase automation, and promote more effective business processes. (*Id*. at 10, 16, 19.) These initiatives allow IAWC to complete more work with fewer people, at lower labor and related costs to IAWC's customers than in 2011. (*Id.* at 19.)

d. Staff and Intervenors' further reductions to IAWC's test year headcount and payroll expense are unreasonable, and should be rejected.

No party disputed that IAWC's approach to staffing its operations is reasonable, and no party disputed IAWC's current headcount, or the need for the 24 full-time positions that IAWC is recruiting for and plans to fill in 2016, or the need for the attendant work. Further, no party disputed that IAWC may need to recruit for more positions in 2016 and 2017, to meet its service obligations to Illinois customers. (IAWC Ex. 2.00SR at 6.)

But Staff witness Kahle, AG witness Effron, and IIWC/FEA/CUB witness Gorman proposed to further reduce IAWC's test year headcount and payroll expense, based on nothing more than IAWC's historical position vacancies since 2014, albeit each to varying degrees. (*Id.* at 2.) Mr. Kahle would reduce the expense by 5.40%; Mr. Effron, by 5.77%; and Mr. Gorman, by 7.59%. (IAWC Ex. 2.00SR at 7; IIWC/FEA/CUB Ex. 2.0 (Rev.) at 26.)

IAWC's undisputed approach to staffing and its staffing needs—and not the Company's recent historical vacancy experience, in isolation—should dictate its 2017 headcount and payroll expense. Otherwise, the result is unjust and unreasonable, for a host of reasons: it ignores the context of IAWC's historic employment levels; it ignores IAWC's immediate need for additional staffing and would disallow currently planned positions that no party disputes are necessary; and it ignores management's need for flexibility in future hiring decisions. Moreover, it ignores that, when headcount is below budget, overtime hours exceed budget, and this offsets any decrease in payroll expense. Simply put, someone has to do the work to meet IAWC's service obligations to customers. When planned positions remain unfilled, that someone is IAWC's current workforce.

i. IAWC is already operating with a lean staff, so its historical vacancy experience is not representative of its future staffing needs.

No party disputed IAWC's planned hires represent a lean staff—IAWC has already significantly reduced its headcount by 26 full-time positions since its last rate case, not even accounting for IAWC's anticipated 12 position vacancies. (IAWC Ex. 2.00R (2d Rev.) at 6.) This is one benefit of Business Transformation, which was established in 2013. Business Transformation changed the way IAWC employees work; they perform the same functions, just differently and more efficiently. The new systems, for example, enabled a field resource center at the Service Company, which provides centralized scheduling for field work for IAWC and other American Water operating companies, and thus reduced the number of IAWC employees necessary to perform that function. (*Id.*) The advent of Business Transformation in 2013 meant a period of "right-sizing" for IAWC's workforce—in 2014 and 2015. (*Id.*) Thus, IAWC's vacancy experience those years just isn't a good predictor of its future staffing needs.

Moreover, necessarily, IAWC can reduce its workforce only so much; it needs talented employees to meet its service obligations to customers. And the lower the number of full-time positions, the fewer vacancies there can reasonably be. (*Id*. at 8.) Since IAWC is already operating with a lean staff, to reduce that staff even further is unreasonable.

ii. The proposed adjustments to payroll expense would disallow currently planned positions that no party disputes are necessary.

As discussed above, IAWC is already near its test year projected headcount of 470, considering IAWC's May 2016 442 headcount and the 24 positions it is currently recruiting or planning to hire in 2016. Neither Mr. Kahle, Mr. Effron, nor Mr. Gorman disputed the need for the 24 full-time positions that IAWC is currently recruiting for and plans to hire in 2016 alone.

(IAWC Ex. 2.00SR at 6.) And none of them identified any 2016 or 2017 test year activities as unnecessary, which would warrant leaving any positions unfilled those years. (*Id*.)

Yet, in disallowing IAWC's planned test year headcount based on nothing but IAWC's historical headcount, these witnesses arbitrarily removed the cost for the planned 2016 positions that they don't dispute are necessary. Mr. Kahle's 5.40% vacancy adjustment would disallow five positions planned for 2016 that he doesn't dispute the need for. (*Id*. at 7.) Mr. Effron's 5.77% vacancy adjustment would disallow seven, even though Mr. Effron expressly testified that he "do[es] not argue that the positions are unnecessary." (*Id*.; AG Ex. 3.0 at 8:164.) And Mr. Gorman's 7.59% vacancy adjustment would disallow nearly *all* of the positions that IAWC is recruiting for and plans to fill in 2016. In fact, Mr. Gorman advocated a workforce of approximately *64 fewer* employees than in IAWC's last rate case. (IAWC Ex. 2.00SR at 7.) Although, again, neither he nor Messrs. Kahle or Effron disputed the need for *any* of IAWC's currently planned workforce.

iii. The proposed adjustments to payroll expense would effectively eliminate IAWC's flexibility to hire critical personnel in the future.

Staffing utility operations is a dynamic, ongoing process. Headcount requirements aren't static; they vary continuously, depending on operational needs. (IAWC Ex. 2.00R (2d Rev.) at 3.) Those needs may require additional staffing that is not currently planned, like the staff necessary to remedy an unanticipated increase in main breaks due to inclement weather. (IAWC Ex. 2.00 at 18-19.) Utility management must have the flexibility to hire that staff, as circumstances demand, to meet service obligations to customers. (IAWC Ex. 2.00SR at 8.)

Messrs. Kahle's, Effron's, and Gorman's adjustments all would deprive utility management of that flexibility, because the adjustments would limit IAWC to its planned June 2016 staffing needs alone. (Less, in fact, as explained above.) This removes IAWC's flexibility to recruit for and fill new positions in 2016 and 2017, beyond its currently planned staffing needs in IAWC Exhibit 2.01R, as new positions become necessary. (*Id.*)

iv. At a minimum, any payroll expense adjustment requires an offsetting adjustment for increased overtime expense.

When IAWC cannot fill a budgeted position, current employees must perform the work—at time-and-a-half pay—in additional to their other responsibilities, so IAWC can meet its service obligations to Illinois customers. (IAWC Exs. 2.00R (2d Rev.) at 7; 2.00SR at 2, 3-4.) Therefore, where historical headcount vacancies have exceeded budget, IAWC's historical overtime expenses likewise have exceeded budget—by $742,000 in 2013; by $808,000 in 2014; and by $459,000 in 2015. (IAWC Ex. 2.00R (2d Rev.) at 7.) As of May 2016, IAWC's 2016 overtime expense was 69% over budget. (IAWC Ex. 2.00SR at 4.) In other words, on average, 2013 to date, IAWC's overtime expenses have exceeded budget by 43%, offsetting budgeted payroll expense reductions those years.

Additional hires are required to reduce overtime for the current employees, or IAWC's overtime expenses will continue to exceed budget. (*Id.*) The Commission should authorize IAWC's requested payroll expense so that IAWC can appropriately staff its operations. If, however, the Commission finds reason to further reduce IAWC's test year headcount based solely on its historical vacancy experience, as Messrs. Kahle, Effron, and Gorman advocate, then, for symmetry, the Commission should also recognize the consequent increase to IAWC's test year overtime expense that will result. (IAWC EX. 2.00SR at 4.)

Staff witness Kahle agreed. (IAWC-Staff Stip. Cross Ex. 1.0 at. 18, 20.) IAWC's projected test year overtime expense is $1,311,710. (IAWC Ex. 2.00SR at 4.) Applying IAWC's historical average overtime expense variance of 43% to the test year expense level produces an increase in overtime expense of $559,444. (*Id.*) In discovery, Mr. Kahle agreed that increase appropriately offsets his $702,756 payroll expense adjustment, reducing the adjustment to $143,312. (IAWC-Staff Stip. Cross Ex. 1.0 at 18, 20.)

IAWC has already significantly reduced its workforce, which has mitigated the payroll expense that customers pay through rates. The Commission should support such efforts. It shouldn't constrain payroll expense—and, consequently, IAWC's ability to fill necessary positions with talented, diverse personnel—further. It should reject any adjustment to IAWC's 2017 test year payroll expense.

2. Annual Performance Plan Expense (Resolved between IAWC and Staff)

Part of IAWC's Annual Performance Plan successfully encourages its employees to achieve IAWC's operational goals—safety, customer satisfaction, environmental leadership, and operational efficiency—with pay that depends on their annual performance and IAWC's. Year-over-year 2013 to 2015, IAWC drove down safety incident rates and increased customer satisfaction rates, under annual performance pay metrics. And IAWC has so increased its operational efficiency that its overall operating expenses in this case reflect a 3% *decrease* from those in the Company's 2011 rate case. Unquestionably, Illinois customers have benefitted from these operational successes.

IAWC initially requested full recovery of its Annual Performance Plan expense. However, to narrow the issues, it accepted Staff's proposed adjustment to allow only the portion that encourages IAWC's operational successes. Therefore, Staff, IAWC, and IIWC/FEA/CUB now agree that portion of the Annual Performance Plan expense is recoverable.

AG witness Effron, however, would disallow IAWC's entire Annual Performance Plan expense, including the portion that encourages IAWC's operational successes. But, notably, Mr. Effron doesn't dispute that IAWC reasonably compensates its employees, or that the Annual

Performance Plan encourages their operational achievements, or even that those achievements benefit Illinois customers. Rather, Mr. Effron homes in on one feature of the Annual Performance Plan that ensures that IAWC can fund it before payouts are made. From this alone, Mr. Effron decides that the plan expense should be disallowed in its entirety.

Mr. Effron's position ignores the facts and the law. The Commission should reject so disproportionate a result. It should approve Staff's proposed partial recovery of IAWC's Annual Performance Plan expense, which IAWC has accepted to narrow the issues.

a. Prudent and reasonable employee compensation expenses are recoverable.

Utility rates must allow the utility to recover its prudent and reasonable costs of service. *Citizens Util. Bd. v. Ill. Commerce Comm'n*, 166 Ill. 2d 111, 126 (1995). This includes the utility's prudent and reasonable expenditures to compensate employees. *See People ex rel. Madigan v. Ill. Commerce Comm'n*, 2011 IL App (1st) 100654, ¶ 49 (*citing Bus. & Prof'l People for Pub. Interest v. Ill. Commerce Comm'n*, 146 Ill. 2d 175, 247 (1991); *Villages of Milford v. Ill. Commerce Comm'n*, 20 Ill. 2d 556, 565 (1960)).

b. Performance pay that benefits customers is specifically recoverable.

Generally, when part of the compensation a utility pays its employees is at risk (like incentive or performance pay), recovery of the expense hinges on whether it benefits customers. *See, e.g.*, *N. Shore Gas Co. et al.*, Dockets 07-0241/0242 (cons.), Order at 66 (Feb. 5, 2008) ("The main and guiding criterion is that the [incentive pay] expense be prudent, reasonable and operate in a way to benefit the utility's customers."); *Madigan*, 2011 IL App (1st) 100654, ¶¶ 51, 55 (affirming the Commission's customer benefit standard). The Commission has consistently found that performance pay that promotes safety, increases customer satisfaction, and controls operating expenses benefits utility customers, is rate recoverable. *See, e.g.*, *Ameren Ill. Co.*, Docket 15-0142, Order at 44-46 (Dec. 9, 2015); *N. Shore Gas Co. et al.*, Dockets 12-0511/0512 (cons.), Order at 130 (June 18, 2013) ("One of the goals that the Commission encourages public utilities to incentivize through [incentive pay] plans is the control and reduction of operating costs since . . . this should have the effect, all else being equal, of lowering the costs to be recovered in future rate cases.").

c. IAWC prudently and reasonably compensates its employees.

Like its industry peers, IAWC compensates employees with a mix of base pay, overtime pay, and short- and long-term performance pay. Performance pay is pay that varies depending on the individual employee's and the broader Company's performance. (IAWC Exs. 9.00R at 4; 2.00 at 20.) *See also N. Shore Gas Co. et al.*, Dockets 07-0241/0242 (cons.), Order at 66 (Feb. 5, 2008) ("Being a large utility means that management depends on the dutiful work performance of its employees. To motivate and maintain high standards, a utility may reasonably offer incentive compensation, as the best way to match both employer and employee interests and to ensure quality work performance."). Also like its peers, to compete for talented employees, IAWC targets its employees' total compensation—base pay plus performance pay—at the market median for comparable positions. (IAWC Ex. 9.00 at 4-5.)

In 2015, the total compensation that IAWC paid its employees was somewhat below both the national and Midwest market medians, by 16% and 15%, respectively. (IAWC Ex. 9.00 at 8.) IAWC employees' 2015 base pay alone was substantially below those market medians, by 28% and 25%, respectively. (*Id*. at 9.) In other words, any way you slice it, IAWC's employees are not overcompensated. Further, if IAWC employees did not receive their performance pay—and received base pay alone—they would be significantly underpaid relative to their peers. (*Id*. at 9; IAWC Ex. 7.00R (Rev.) at 23.) *Cf. Commonwealth Edison Co.*, Docket 14-0312, Order at

49-50 (Dec. 10, 2014) (finding the utility should be allowed to recover close to market-level employee compensation, including incentive pay).

d. IAWC employees' compensation includes performance pay that benefits customers.

IAWC awards its employees short-term performance pay under the Annual Performance Plan. (IAWC Ex. 2.00 at 20, 22-23; ICC Staff Ex. 3.0, Attach. G at 4-16 (plan document).)[17] Payouts under the Annual Performance Plan depend 50% on the Company's financial performance, assessed via earnings per share metrics, and 50% on its operational performance, assessed via safety, customer satisfaction, environmental leadership, and operational efficiency metrics. (IAWC Exs. 2.00R (2d Rev.) at 12; 9.01 (Rev.) at 7-8.) The plan also requires that the Company be financially able to fund it, assessed as attaining 90% of an earnings per share goal, before payouts can be made. (IAWC Ex. 9.00 at 10.) This isn't, however, a performance metric under the plan on which employees are paid. (*Id.*)

The Annual Performance Plan's operational goals benefit IAWC's customers. In 2013, 2014, and 2015, IAWC employees achieved these incremental and sustained operational successes, under its short-term performance pay plans:

OPERATIONAL METRIC	2015	2014	2013
OSHA Recordable Incident Rate	1.24	1.80	2.38
OSHA Days Away/Restricted or Job Transfer Rate	0.62	1.20	1.79
Customer Satisfaction	93%	92%	90%
Service Quality	87%	85%	85%
Commission Complaints	245	502	284
O&M Efficiency Ratio	38.3%	42.0%	44.3%

(IAWC Ex. 2.00R (2d Rev.) at 12-13.)

[17] The Long Term Performance Plan, under which IAWC awards long-term performance pay, is not at issue here. *See infra* § VI.B.12.

Safety incidents went down. Customer satisfaction and service quality went up. And operational efficiency increased such that the total test year operating expenses that IAWC initially requested in this case—$98.7 million—were *3% less* than in its last rate case, despite inflation and despite that, in this case unlike Docket 11-0767, IAWC requested recovery of its performance pay expenses. (IAWC Exs. 2.00 at 5; 2.00R (2d Rev.) at 11; 7.00SR (Rev.) at 11.) This reduction has not only mitigated the operating costs that IAWC's customers ultimately pay through rates, but also delayed the time between IAWC's rate cases. (IAWC Ex. 2.00R (2d Rev.) at 11-12, 14.)

IAWC's customers unquestionably have benefited from its achievement of the operational goals incentivized by the Annual Performance Plan. (IAWC Ex. 7.00R (Rev.) at 34.) Therefore, Staff, IAWC, and IIWC/FEA/CUB agreed that the attendant costs should be recoverable. IAWC initially requested 100% recovery of its Annual Performance Plan expense. But, to narrow the issues, IAWC accepted Staff's proposed adjustment to allow recovery of the portion that encourages IAWC's operational successes. (ICC Staff Ex. 3.0 at 10, Sch. 3.07; IAWC Exs. 7.00SR (Rev.) at 10-11; 4.00SR at 6-7; IAWC-Staff Stip. Cross Ex. 1.00 at 17, 19.) IIWC/FEA/CUB witness Gorman proposed an adjustment that approximates Staff's. (IIWC/FEA/CUB Exs. 1.0 at 14; 1.4; 2.0 (Rev.) at 34 (advocating partial recovery of IAWC's short-term performance pay costs).)

AG witness Effron, however, would disallow all of IAWC's Annual Performance Plan expense, including the operational goal related portion. It is that portion—the portion that incents IAWC's operational successes—that remains at issue.

e. AG witness Effron would disallow the entire plan expense, even though he didn't dispute the prudence and reasonableness of IAWC's pay practices or that the Annual Performance Plan's operational goals benefit customers.

AG witness Effron didn't dispute that IAWC prudently compensates its employees, or that IAWC employees' total compensation is reasonable. (IAWC Ex. 9.00R at 2-3; IAWC-AG Stip. Cross Ex. 1.00 at 1-2, 4.) Nor did he dispute that IAWC employees' operational achievements under the Annual Performance Plan have benefited customers. To the contrary, AG witness Effron expressly agreed that customers benefit when a utility reduces its operating expenses—like IAWC has here—so long as safe, reliable, and least-cost service isn't compromised—which clearly hasn't happened here: safety and customer service have improved. (*Id.* at 3; *supra* § IV.A.2.d.)

Nevertheless, Mr. Effron asked the Commission to disallow *all* of IAWC's Annual Performance Plan expense. He homes in on the plan feature that requires its financial viability to fund it, and, from this, summarily concludes that the entire plan primarily benefits shareholders. (AG Ex. 1.0 at 14.) Mr. Effron's position is simply too narrow. It ignores the record evidence and the law, and would unfairly disallow the cost of operational metrics that he doesn't dispute benefit customers.

f. Mr. Effron's position, in focusing on only the financial viability feature of the Annual Performance Plan, ignored the record evidence.

Mr. Effron's position also ignored key record facts. It first ignored that the financial viability aspect of the Annual Performance Plan isn't a performance metric on which participants are paid. (IAWC Ex. 9.00 at 10.) In other words, increasing earnings per share doesn't affect payouts under the operational side of the plan. Instead, the only way that IAWC employees can earn that performance pay, and even increase it, is to meet or exceed IAWC's operational goals—safety, customer satisfaction, environmental leadership, and operational efficiency. (IAWC Exs. 2.00R (2d Rev.) at 12; 9.01 (Rev.) at 7.) Again, these are goals that benefit customers—a point Mr. Effron did not dispute.

Mr. Effron's position also ignored that, despite the financial viability aspect of its short-term performance pay plans, IAWC employees have consistently received performance pay under the plans every year, for at least the last seven. (IAWC-AG Stip. Cross Ex. 2.00 at 2.) In fact, on average, payouts have exceeded the target level—the level at which IAWC set performance pay in its revenue requirement in this case. (*Id.*; IAWC Ex. 2.00 at 21.) This means that IAWC employees can reasonably be expected to meet or exceed their Annual Performance Plan operational goals in the test year; IAWC can reasonably be expected to award them for that performance; and customers can reasonably be expected to benefit, the financial viability aspect of the plan aside. *See N. Shore Gas Co. et al.*, Dockets 07-0241/0242 (cons.), Order at 67 (Feb. 5, 2008) ("Taken together, the goal of the [incentive pay] plan, the large pool of potential awardees and the wide-reaching motivational impact, make it more likely than not, that ratepayers will benefit from the race to excellence.")

g. Mr. Effron's position, in focusing on only the financial viability feature of the Annual Performance Plan, also ignored the law.

Mr. Effron's position ignored that the Commission consistently approves cost recovery for performance pay operational metrics that benefit customers, such as safety, customer satisfaction, and operational efficiency. *See, e.g.*, Dockets 07-0241/0242 (cons.), Order at 66 (when incentive pay tied to "matters of customer service, customer satisfaction, the reduction of operating expenses, and the like is at hand, it is incumbent upon the Commission to take a close and considered view"); *supra* § IV.A.2. These are the very goals that the Annual Performance Plan incentivizes, to the undisputed benefit of IAWC's customers in 2013, 2014, and 2015.

Moreover, recognizing that operational performance pay metrics benefit customers, the Commission has approved cost recovery even when the governing plan includes a financial feature, to avoid an unjust and disproportionate result. *See, e.g.*, *Commonwealth Edison Co.*, Docket 14-0312, Order at 48-51 (Dec. 10, 2014).

In Docket 14-0312, the Commission approved partial recovery of ComEd's Annual Incentive Plan, which consisted of eight operational metrics on which ComEd employees received annual incentive pay as well as a "Shareholder Protection Feature" that relied on a reference to Exelon's earnings per share performance. *Id.* Like the financial viability feature of IAWC's Annual Performance Plan, ComEd's Annual Incentive Plan's Shareholder Protection Feature could limit the amount of annual incentive compensation paid, but it was not a metric on which ComEd employees earned their annual incentive compensation. *Id*. at 29.

In Docket 14-0312, like here, no party disputed that ComEd's Annual Incentive Plan metrics incented employees to meet goals that are beneficial to ratepayers. *Id*. And there, like here, the record showed that if employees did not receive their annual incentive pay, they would receive below market wages. *Id*. In light of this, the Commission found that ComEd should recover its Annual Incentive Plan costs, at 102.9% payout, which the Commission concluded "insures that ComEd recovers the market-based salary for their employees plus a reasonable bonus which further serves to encourage employees continued achievement of the operational goals to the befit of ratepayers, without allowing for excess cost recovery." *Id*. at 50. The Commission rejected the AG's proposed 100% disallowance of ComEd's Annual Incentive Plan—based only on the existence of the Shareholder Protection Feature—as disproportionate. *Id*. at 49.

h. Mr. Effron's position is disproportionate—it would disallow 100% of indisputably reasonable compensation expense that benefits customers.

Mr. Effron's proposed 100% disallowance of IAWC's Annual Performance Plan expense here, like the AG's proposed disallowance in Docket 14-0312, is disproportionate. Again, no party disputed the customer benefits from IAWC's Annual Performance Plan operational metrics. And even including *all* of IAWC employees' short-term performance pay (IAWC has already accepted Staff's adjustment to recover only a portion), IAWC employees' total compensation is already slightly below market. To allow recovery of $0 of the Annual Performance Plan expense, as Mr. Effron advocated, would be unjust and unreasonable.

The Commission should avoid so disproportionate a result. It should accept Staff's adjustment to allow partial recovery of the Annual Performance Plan expense, which IAWC has accepted to narrow the issues.

3. Purchased Power Expense

IAWC relies on electricity to power its buildings, pumping stations, and treatment plants. Like many large consumers of electricity, IAWC hedges its electricity costs by entering into power supply agreements. (*See* IAWC Ex. 2.00R (2d Rev.) at 15.) Rates under these agreements are based on the wholesale price of energy and capacity in the PJM[18] and MISO[19] regions. (*Id.*) The capacity component is based on annual auctions. (*Id.*) Test year purchased power expense is based on two power supply agreements (one each for MISO and PJM), which the Company entered in September 2015. (*Id.*; IAWC Ex. 4.00 at 13. *See also* Sch. C-2.2.) Capacity costs account for 15-20% of total retail power costs under these agreements. (*Id.*)

---

[18] PJM Interconnection
[19] Midcontinent Independent System Operator

After IAWC filed its case, MISO announced lower capacity costs for its June 1, 2016 through May 31, 2017 planning year. (AG Ex. 1.0 at 20-21.) The AG argued that purchased power expense should be reduced by $219,000 to account for these new capacity prices. (*Id.* at 21.) The Commission should reject this adjustment because it is overstated.

The AG's adjustment is overstated in two important ways. First, lower capacity prices will go into effect only in the MISO region, and only then for half of the test year. (IAWC Ex. 2.00R (2d Rev.) at 16.) The PJM contract prices will remain as forecast. (*Id.* *See also* AG Grp. Ex. 1.0, AG-14.001 and AG-14.001 Attach.)

Second, the AG's proposed adjustment to reflect a capacity cost decrease does not account for increases in other components of IAWC's purchased power costs, including increases in Ameren Illinois Company and ComEd distribution rates. (IAWC Ex. 2.00R (2d Rev.) at 17.)

The AG's proposed adjustment assumes that capacity prices for the final seven months of the 2017 test year will continue at the level announced for the first half of 2017, but there is no reason to believe that this will be the case. (IAWC Ex. 2.00R (2d Rev.) at 16.) Recent history shows that MISO capacity prices have been extremely volatile: costs for the 2013/2014 planning year were $1.05/megawatt day; they rose to $16.75/megawatt day in 2014/2015; rose again, significantly, to $150/megawatt day in 2015/2016; and then fell to $72/megawatt day for the 2016/2017 planning year. (*Id.* at 15; AG Ex. 1.0 at 20-21.) These dramatic swings highlight the likelihood that capacity charges will increase again in the latter seven months of 2017. And if that happens, the AG's adjustment would shortchange IAWC's full recovery of purchased power costs. (IAWC Ex. 2.00R (2d Rev.) at 16-17.)

The Commission should reject the AG's adjustment and approve recovery of purchased power costs incurred under the September 2015 power supply agreements.

4. Test Year Sales Level

In a general rate case, the Commission sets a utility's revenue requirement based on the utility's expenses during a test year plus a return on invested capital, or rate base. (*See* IAWC Ex. 4.00 at 4); *see also People ex rel. Madigan v. Ill. Commerce Comm'n*, 2015 IL 116005 at P7. The Commission then authorizes the utility to charge rates designed to collect revenues equal to the revenue requirement. When the utility uses a future test year, as IAWC has done in this case, its expenses during the test year must be forecasted to develop a revenue requirement. (IAWC Ex. 4.00 at 5.) Likewise, because utility rates incorporate a volumetric charge, the total sales volumes must be forecasted to ensure that rates will recover the total revenue requirement. The objective in a future test year case is to forecast sales as accurately as possible, so that the forecast reflects actual conditions in the test year, and the utility can set rates that allow it to earn its authorized revenues. If actual revenues from sales in the test year do not match forecasted revenues in the test year, the utility will either under- or over-recover its costs. (ICC Staff Ex. 8.0 at 4.)

a. IAWC's sales volumes are declining

It is undisputed that IAWC's sales volumes are declining. IAWC estimates that the decline in use per residential customer is approximately 2.03% per year, (IAWC Ex. 8.00SR at 6, Table 8.02), while use among commercial customers is declining at a rate of 0.4% per year. (IAWC Ex. 8.00 at 6.) Staff agreed that IAWC's sales volumes have "a downward trend in average monthly use per residential customer," of approximately the same percentage as the Company forecasted. (ICC Staff Ex. 8.0 at 5:104-105.) IIWC/FEA/CUB witness Gorman agreed that IAWC's water usage has exhibited a declining trend, (IIWC/FEA/CUB Ex. 2.0

(Rev.) at 3), and IIWC/FEA witness Collins did not dispute the existence of a declining trend in usage. (IIWC/FEA Ex. 1.0 at 12.)

The decline in residential and commercial usage is driven by customers' installation of new low-flow fixtures and appliances, as well as customer awareness of water conservation and efficiency initiatives. (IAWC Ex. 8.00 at 9-11.) Federal law mandates water efficiency standards for fixtures and appliances, which have been growing more stringent over time. (*Id*. at 11.) More than 87% of homes in Illinois were constructed before federal water efficiency standards took effect, and were constructed with more water-intensive fixtures. (*Id*. at 17.) As customers replace older water-intensive fixtures with fixtures that meet the federal mandates, their demand for water declines. (*Id*. at 11-12.) The decline in usage among IAWC's customers over the last ten years is evidence of the effectiveness of the federal mandates and education programs. However, the mandates are relatively new in comparison to the life expectancy of appliances and fixtures, and many customers have not replaced all of their older water-intensive fixtures with newer efficient ones. (*Id*. at 17; 8.00R (Rev.) at 4.) In addition, more stringent efficiency standards are under consideration. (IAWC Ex. 8.00 at 17-18.) Therefore, usage will likely continue to decline through the 2017 test year—and beyond. (IAWC Ex. 8.00R (Rev.) at 4.)

The decline is significant, both in terms of gallons and in terms of revenue dollars. From 2006 through 2015, IAWC sold 17.8 billion fewer gallons than was used to determine its Commission-approved revenue requirements. (IAWC Ex. 8.00 at 15.) Over 60% of IAWC's revenues are variable—recovered via per-gallon volumetric charges—but over 90% of the Company's costs are fixed. (IAWC Ex. 7.00 at 6-7.) When customer usage and sales volumes decline, as IAWC's have, and its rate structure relies heavily on volumetric charges, as IAWC's does, the rates do not produce enough revenue to cover the utility's costs. (*Id*. at 5.) Because IAWC's rate structure relies heavily on volumetric charges, (*id*. at 6), this shortfall in gallons sold led IAWC to under-recover its approved revenue requirements by approximately $51 million between 2006 and 2015. (IAWC Ex. 8.00 at 15.)

b. In order to accurately forecast its test year sales in a declining use environment, IAWC used a statistical model that produced highly reliable results.

IAWC developed its forecasted test year sales volumes by conducting a statistical regression analysis using base usage data. (IAWC Ex. 8.00 at 5-6.) A regression analysis is the best method for modeling a trend in data, because the analysis estimates the relationship between variables—in this case, time and usage per customer. (IAWC Ex. 8.00SR at 3.) A regression analysis calculates a trend line that best matches and incorporates singular data points—in this case, data points representing usage per customer at particular points in time. (*See* IAWC Exs. 8.01, 8.02.) Mr. Gorman and Mr. Collins agreed that a regression analysis is the appropriate method for calculating a trend in data. (IAWC Ex. 8.00SR at 3 (citing data request responses IAWC-IIWC/FEA/CUB 2.06, IAWC-IIWC/FEA 2.04).)

IAWC's regression analysis relied on a robust data set, and produced highly reliable results. The data set included the average usage per customer per day in each month, for each customer in the residential and commercial classes, over the 10-year period 2006 through 2015. (IAWC Ex. 8.00 at 5.) The 10-year period is appropriate because, in statistics, a greater number of observations, a larger data set, yields more significant explanatory values. (IAWC Ex. 8.00R (Rev.) at 10.)

For purposes of conducting the regression analysis, IAWC excluded weather-dependent usage from its data set. (IAWC Ex. 8.00 at 7-8.) It is necessary to separate weather-sensitive usage from base usage in order to ensure that the result of the analysis (the trend line) measures only trends that exist independently from fluctuations in weather. (IAWC Ex. 8.00SR at 4.) In addition, unlike an analysis based on weather normalization, which requires an assumption that weather in the forecasted period will be equal to "normal" weather, an analysis of base usage does not require the Company or the Commission to make *any* assumptions regarding weather during the forecasted period because it considers only usage that is not driven by weather. (*Id*. at 7.)

The results of IAWC's regression analysis are highly reliable. The trend line that resulted from the regression has a 99.5% change of correctly predicting usage in the test year. (*Id*. at 2.) In other words, there is a 0.05% chance that usage in the test year will be significantly different than usage predicted by IAWC's regression analysis.

c. Intervenors' use of an averaging methodology to forecast test year sales is unreliable.

Although all parties agreed that IAWC's residential sales volumes are trending down, the parties disagreed about how the decline should be forecasted into the test year. Staff and IAWC agreed that residential usage should be forecasted using the 2.03% decline per year, and commercial usage should be forecasted using the 0.4% decline per year. (IAWC Ex. 8.00 at 6; ICC Staff Ex. 8.0 at 5.) But Mr. Gorman and Mr. Collins argued that residential usage in the test year should be assumed to be equal to average usage over the 2011-2015 period, while commercial usage in the test year should be set equal to usage in 2015. (IIWC/FEA/CUB Ex. 2.0 (Rev.) at 9; *see also* IIWC/FEA Ex. 2.0 at 7.) In the face of the Company's statistical evidence, and despite their agreement that a regression analysis is an appropriate method for analyzing trends in data, Mr. Gorman and Mr. Collins argued that a simple average of monthly usage over the five-year period 2011-2015 is a suitable predictor of residential usage in the test year, and that the entire regression analysis should be ignored when forecasting commercial usage. These contentions must be rejected, for several reasons.

First, an average cannot account for a trend in the data being averaged. Consider the example provided by IAWC witness Roach: the simple number set 12, 11, 10, 9, 8 represents a trend. "Given the trend, the next number in the set would logically be 7. But if one were to average the data points, as Mr. Gorman and Mr. Collins did, the result would be 10." (IAWC Ex. 8.00R (Rev.) at 3:49-52.) This same logic holds true here. Residential usage among IAWC's customers exhibited a declining trend over the five years between 2011 and 2015. (IAWC Ex. 8.00SR at 5; *see also* IIWC/FEA/CUB Ex. 2.0 (Rev.) at 3 (expressing Mr. Gorman's agreement that usage is subject to a declining trend).) According to IAWC's regression analysis, and in accordance with the logic of the example above, forecasted usage in 2017 will be lower than actual usage in 2015. According to Mr. Gorman, however, usage in the 2017 test year will equal average usage between 2011 and 2015. (IIWC/FEA/CUB Ex. 2.0 (Rev.) at 9.) But that average amount of usage is *higher than actual* usage among IAWC customers in 2013, 2014, and 2015. (IAWC Ex. 8.00SR at 4.) In other words, usage has already declined below the level Mr. Gorman and Mr. Collins proposed to incorporate into the forecast. (*Id.*) These examples illustrate that a forecast based on an average is inaccurate when the data being averaged is subject to a trend.

Second, because the data Mr. Gorman and Mr. Collins relied upon in developing their average includes weather-sensitive usage, it requires acceptance of the inherent assumption that weather in the forecasted period will be similar to weather in the period averaged. Mr. Gorman explicitly recognized that his analysis relies on assumptions about weather during the test year, stating, "weather and rainfall during the period 2011-2015 was representative of normalized weather conditions for Illinois." (IIWC/FEA/CUB Ex. 2.0 (Rev.) at 7:70-71.) However, because water usage is driven in large part by precipitation, rather than primarily by temperature (like electric and natural gas usage), there is no generally-accepted weather normalization methodology in the water industry. (IAWC Ex. 8.00 at 8.) Therefore, Mr. Gorman's technique of averaging five years of usage as an attempt to normalize for weather is entirely arbitrary.

In addition, Mr. Gorman's contention that weather during the 2011-2015 period was "relatively close to normal" is demonstrably untrue. (*See* IIWC/FEA/CUB Ex. 1.0 at 7:108.) During 2012, weather in Illinois was extraordinarily hot and dry; it was between 25 and 30% warmer than the 40-year average and between 34 and 60% drier than the 40-year average. (IAWC Ex. 8.00R (Rev.) at 6.) But data from 2012 represents one-fifth of the data on which Mr. Gorman's analysis relied upon. Because Mr. Gorman must assume that weather in the test year will correspond to weather during the five-year period he averaged, but that five-year period includes extraordinary weather, his approach is unreliable. In contrast, the Company's analysis, which relied on data regarding base usage, requires *no such assumptions* regarding weather in the forecasted period. (IAWC Ex. 8.00SR at 7.) As such, it is a far more reliable basis for a forecast. (IAWC Ex. 8.00 at 8.)

The Commission should forecast residential usage per customer using the results of IAWC's regression analysis. All parties agreed that usage is declining, and that regression analysis is an appropriate method to measure the rate of decline over time. Even though the intervenors agreed on these points, they did not conduct a regression analysis of their own. The averaging approach the intervenors propose to use instead cannot capture the trend in usage data, is arbitrary, and is based on data that does not reflect normal usage. The Commission should reject the intervenors' proposal to forecast residential usage per customer using a simple average of usage over the 2011-2015 period.

d. Mr. Gorman's proposal to set commercial sales equal to those in 2015 is not supported.

In his rebuttal testimony, Mr. Gorman states, "test year commercial sales should be left at the 2015 level." (IIWC/FEA/CUB Ex. 2.0 (Rev.) at 9:113-14.) The only argument in support of that proposal is a statement that IAWC witness Roach's "analysis of trends in base [c]ommercial usage is flawed." (*Id*. at 5:56.) The testimony contains no explanation of the purported flaws in IAWC's analysis of commercial usage. Without this key information, the proposal is unsupported and must be rejected. The Commission should instead rely on the Company's regression analysis to forecast sales and revenues in the test year.

5. Uncollectible Rate in Lincoln

To provide a reasonable, consistent approach across its service territories, IAWC used a 0.95% uncollectible rate for all of its districts. AG witness Effron, however, proposed a separate uncollectible rate of 0.92% for the Lincoln district only. (AG Exhibit 1.0 at 5.) Maintaining separate uncollectible rates for each rate zone adds to the complexity of preparing a rate case and preparing the Company's annual business plan. (IAWC Ex. 4.00R at 15.) During the budgeting process, the Company incorporated an overall uncollectible rate that was used for all service districts. The Company used one set of depreciation rates for all rate zones, for example, rather than preparing multiple costly depreciation studies. The Company's use of one uncollectible rate to forecast uncollectibles for the entire Company is similarly reasonable, and the use of one uncollectible rate, and one gross revenue conversion factor, for all tariff groups is consistent with the Company's last rate case, Docket 11-0767, and previous rate cases, Dockets 07-0507, 02-0690, and 00-0340.

Mr. Effron's proposal is also unnecessary: it reduces the Lincoln revenue requirement by less than $1,500, or $0.01 per typical residential customer bill. (IAWC Ex. 4.00R at 15.) Mr. Effron's proposal should be rejected.

6. Demand Study Costs

AG witness Rubin agreed with IAWC's proposal that its demand study be discontinued, but recommended that the Company's revenue requirement be reduced by approximately $69,000 for test year demand study costs. (AG Exs 2.0 at 16-17; 4.0 at 1-2.) This adjustment is unnecessary. Mr. Rubin is correct that IAWC expects to incur this amount for demand study data collection and analysis in 2017. (IAWC Exs. 4.00R at 19; 4.00SR at 11.) But these costs are accounted for as deferred expenses, so they are not reflected in the test year revenue requirement and IAWC is not seeking to recover them in the current rate case. (IAWC Exs. 4.00R at 19; 4.00SR at 11-12.) As a result, Mr. Rubin has proposed to disallow costs that are already not in the test year.

IAWC's treatment of the demand data collection costs is consistent with its prior cases. In the Company's last rate case, internal demand study costs were incurred during the test year ending September 30, 2013, but those costs were deferred to Account 186 to be recovered in the current rate case. The Company has also included in deferred current rate case expense actual and forecasted internal demand study costs through the end of December 2016. These deferred costs are then amortized as rate case expense. The amount Mr. Rubin proposed to remove is recorded in a deferred account, and so is already not part of the test year. No adjustment is needed to remove an amount that is already not reflected in the test year. (IAWC Ex. 4.00SR at 12.)

B. Resolved Issues

1. State Income Tax Rate

IAWC proposed to revise the state effective income tax rate in developing the gross revenue conversion factor and income tax expense for IAWC in this case. The state effective income tax rate that correctly reflects IAWC's cost of state income taxes in Illinois is 7.75%, calculated using the Illinois statutory state income rate of 5.25%, plus the Illinois replacement tax rate of 2.5%, multiplied by an apportionment factor of 100%. (IAWC Ex. 13.00R at 3.) IAWC determined that it was incorrectly using a five-year average estimate of American Water's apportionment factor when it should have been using the 100% apportionment factor reflecting IAWC's activities in the State of Illinois, since all of IAWC's sales are sourced to Illinois. (*Id.*) Using a 100% apportionment for IAWC properly represents IAWC activities and the amount it will ultimately pay as its share of the American Water combined group. (*Id.*)

Staff witness Hathhorn and AG witness Effron both accepted IAWC's proposal to use the 7.75% state income tax rate, based on a 100% apportionment factor. (ICC Staff Ex. 10.0 at 4; AG Ex. 3.0 at 2.) Therefore, this issue is resolved.

2. Income Tax Expense

In rebuttal, AG witness Effron stated that while the Company appears to agree with his corrections to the calculation of income tax expenses, the Company still had not made those corrections. (AG Ex. 3.0 at 15.) In surrebuttal, IAWC witness Kerckhove explained that the current income tax was calculated correctly in the Company's rebuttal testimony. However, the adjustment to income tax expense used in the Company's rebuttal filing was an error since it used the Company's initial rate case filing as the starting point for the adjustment. The current income taxes in the Company's surrebuttal exhibits match the calculation of income tax expense on Company Pro Forma Present. (IAWC Ex. 4.00SR at 11.) As a result, this issue should be resolved.

3. Advertising Expense

Schedule C-8 presents IAWC's expenses for advertising that informs consumers how they can conserve water or reduce peak demand, advertising required by law, and advertising regarding service interruptions, safety measures, and emergency conditions. (IAWC Ex. 4.00 at 19.) Staff witness Kahle proposed an adjustment to reduce the Company's proposed advertising expense level by items he deemed of a promotional, goodwill or institutional nature. (ICC Staff Ex. 3.0 at 7, Sch. 3.03 at 1.) IAWC accepted that adjustment. (IAWC Ex. 4.00R at 4.) Therefore, this issue is resolved.

4. Lobbying Expense

Schedule C-2.5 presents lobbying expenses that IAWC removed from the test year revenue requirement. (IAWC Ex. 4.00 at 14.) Staff witness Kahle proposed an additional adjustment for employee expenses related to lobbying that IAWC inadvertently included in test-year operating expenses. (ICC Staff Ex. 3.0 at 9, Sch. 3.05.) IAWC accepted that adjustment. (IAWC Ex. 4.00R at 4.) Therefore, this issue is resolved.

5. Outside Professional Services Expense

Schedule C-6.2 presents expenses for Outside Professional Services 2014 through 2017. (IAWC Ex. 4.00 at 18.) Staff witness Kahle and AG witness Effron each proposed an adjustment to remove certain outside professional expenses that IAWC inadvertently included in test-year operating expenses. (ICC Staff Ex. 3.0 at 10, Sch. 3.06; AG Ex. 1.0 at 25.) IAWC accepted that adjustment. (IAWC Ex. 4.00R at 4.) Therefore, this issue is resolved.

6. Invested Capital Tax

Schedule C-2.10 presents an adjustment to the test year forecast for invested capital tax that aligned with IAWC's initially-proposed capital structure balances. (IAWC Ex. 4.00 at 15.) Staff witness Kahle recommended that the final amount of invested capital tax be based on the average combined long-term debt and common equity from the capital structure adopted by the Commission. (ICC Staff Ex. 3.0 at 9.) AG witness Effron agreed. (AG Ex. 3.0 at 17.) In light of the parties' agreement regarding the capital structure balances, IAWC accepted the adjustments to invested capital tax. (IAWC Exs. 4.00R at 13, 4.00SR at 10.) Therefore, this issue is resolved.

7. Unaccounted-For Water Expenses

Staff witness Kahle originally recommended an adjustment to reduce chemical and power expenses associated with the unaccounted-for water over the maximum allowance in IAWC's tariffs. (ICC Staff Exs. 3.0, Sch. 3.02, 7.0 at 6.) IAWC already removed, however, the excess production costs above the tariff limitations, as shown in workpapers WPC-2.2c and WPC-2.2d. (IAWC Ex. 4.00R at 11.) Further, Staff's calculations overstated the appropriate adjustment—already included in IAWC's calculations—because they did not reflect the full amount of water not used for billed sales but used for known purposes, and because they included a weighted factor for the lower unaccounted-for water tariff limits in the Chicago Metro district's purchased water areas. (*Id*. at 12.) Staff witness Sperry did not object to IAWC's calculations, and recommended that the Commission accept IAWC's adjustment for unaccounted-for water. (ICC Staff Ex. 15.0 at 5.) Therefore, the issue is resolved.

8. Depreciation/Amortization Adjustment

IAWC included a depreciation adjustment in its revenue requirement, as shown on IAWC Schedules C-12 and C-2.11. (IAWC Ex. 4.00R at 18.) Staff witness Effron proposed an adjustment to the depreciation expense shown on Schedule C-2, "in the calculation of adjusted operating income under present rates, to comport with the depreciation expense shown on Schedules C-2.11 and C-12. (AG Ex. 1.0 at 22:502-04.) Mr. Effron's proposal, however, adjusted amortization expense recorded in Accounts 406 and 407 and that was included in IAWC's last three rate cases. (IAWC Ex. 4.00R at 18). Mr. Effron agreed and withdrew his proposal. (AG Ex. 3.0 at 14.) Therefore, the issue is resolved.

9. Miscellaneous/Other Revenues

IIWC/FEA/CUB witness Gorman proposed an adjustment to IAWC's test year Miscellaneous/Other Revenues to more closely align with 2014 and 2015 Miscellaneous/Other Revenues levels. (IIWC/FEA/CUB Ex. 1.0 at 8-9.) AG witness Effron also proposed an adjustment to these revenues to reflect actual revenues through September 2015 and proposed revenues for October through December 2015. (AG Ex. 1.0 at 11-12.) IAWC accepted Mr. Gorman's proposal in part, and proposed that the adjusted level of Miscellaneous/Other Revenues through the 12 months ending May 2016 be used for the 2017 test year. (IAWC Ex. 4.00R at 17, 19-20.) Mr. Effron accepted this adjustment; Mr. Gorman also accepted, it and recommended an increase in Miscellaneous/Other Revenues for the Chicago-Metro Sewer district, since IAWC's proposed time period did not reflect normal operations in this district. (AG Ex. 3.0 at 7; IIWC/FEA/CUB Ex. 2.0 (Rev.) at 22-23.) IAWC accepted Mr. Gorman's adjustment. (IAWC Ex. 4.00SR at 7-8.) Therefore, the issue is resolved.

10. Current Rate Case Expense

IAWC requested rate recovery of $2,829,388 in rate cases expenses, amortized over two years. (IAWC Ex. 4.00 at 19-21.) Of that total, $2,682,915 is the projected cost for outside and affiliate expertise to prepare and litigate this rate case. (*Id*. at 19.) The remaining $146,476 is the unamortized balance of Docket 11-0767 rate case expense, already approved by the Commission as just and reasonable in that rate case. (*Id*. at 20; Sch. C-10, page 1.)[20]

Section 9-229 of the Public Utilities Act requires the Commission to assess the justness and reasonableness of IAWC's rate case expenses. 220 ILCS 5/9-229. In 2015, the Commission adopted the Part 288 rules, which are intended to guide this assessment. 83 Ill. Admin. Code, Part 288; *Ill. Commerce Comm'n on Its Own Mtn.*, Docket 11-0711, Final Order at 1 (June 3, 2015). Consistent with that authority, IAWC has supplied for the Commission's review extensive documentation supporting the justness and reasonableness of its current rate case expenses and, as explained below, IAWC has otherwise complied with Part 288's requirements.

Staff recommended that the Commission approve IAWC's $2,829,388 rate case expenses as just and reasonable under Section 9-229. (ICC Staff Ex. 11.0Rev at 14.) And the parties have agreed to identify this issue as uncontested. In light of this, the record evidence, and IAWC's Part 288 compliance, the Commission should approve IAWC's requested level of rate case expense. *See* 83 Ill. Admin. Code 288.40(a).

a. IAWC has supplied extensive documentation supporting the justness and reasonableness of its current rate case expenses.

IAWC's $2,682,915 current rate case expense projection is composed of expenses for the following rate case work, performed by the following professionals, as shown on Schedule C-10:

- Cash Working Capital study and support – Harold Walker III, Gannett Fleming;
- Cost of Service study and support – Paul R. Herbert, Gannett Fleming;
- Demand Study and support – Paul R. Herbert, Gannett Fleming;
- Forecast Audit – Rick Gratza, Kerber, Eck & Braeckel, LLP;

[20] IAWC also initially requested recovery of $586,491 of unamortized, unrecovered rate case expense approved by the Commission in Docket 09-0319. To narrow the issues in this proceeding, however, IAWC no longer pursues that rate case expense. *See infra* § IV.B.11.

- Rate of Return study and support – Paul R. Moul, Paul Moul & Associates;
- Legal support – Whitt Sturtevant LLP;
- Revenue Requirement support[21] – American Water Works Service Company; and
- Compensation study and support – Robert V. Mustich, Willis Towers Watson.

(IAWC Ex. 4.00 at 29-31; AG Grp. Ex. (Part 1) at 46 (Sch. C-10).)[22]

In direct testimony, IAWC explained what the anticipated rate case work entailed, why it is prudent to anticipate that rate case work, and why IAWC chose the professionals it did to perform the rate case work, including their qualifications and the reasonableness of their fees. (IAWC Ex. 4.00 at 29-45.) IAWC explained, for example, that it engaged Mr. Herbert to perform the cost of service study necessary to support IAWC's proposed rate design because he has substantial experience performing cost of service studies for regulated utilities and for IAWC specifically, including in the Company's last rate case. (*Id.*) Further, the cost for his services reflect reasonable market rates, and are comparable to the same cost in Docket 11-0767. (*Id*. at 31, 41.)

IAWC engaged the same or similar professionals to prepare and litigate Docket 11-0767. The total amount of rate case expense approved in that case for those professional services was $2,332,541; the total amount actually incurred was $2,414,670. (IAWC Ex. 4.00 at 20.) IAWC explained that its current $2,682,915 rate case expense projection is slightly higher due to moderate increases in consultant costs, including the costs for necessary rate case studies, and the

---

[21] Revenue requirement support is Service Company personnel assistance in preparing revenue requirements, testimonies and exhibits, data request responses, analyses, as necessary, and final tariffs. (IAWC Ex. 4.00 at 29.) It also includes the expense for Service Company personnel to attend hearings. (*Id*.)

[22] Schedule C-10 also shows IAWC's projected $250,000 "Internal Demand Study Costs," the costs for utility personnel to continue the data collection and analysis required for the Demand Study ordered in Docket 11-0767, through final resolution of this case. (*See* IAWC-AG Stip. Cross Ex. 2.00 at 6; IAWC Ex. 15.03SR at 11, 33, 63.) Schedule C-10 also includes $200,000 in "Other" costs for customer communications related to the rate case, $110,000 of which IAWC had incurred at the time of its surrebuttal filing. (IAWC-AG Stip. Cross Ex. 2.00 at 6; IAWC Exs. 4.00SR at 14; 4.11SR.)

costs to comply with new legal requirements, such as the enhanced customer notice required by recent amendments to the Public Utilities Act. (*Id*. at 20-21, 30.) *See* 220 ILCS 5/9-201(a).

b. IAWC has otherwise complied with Part 288.

Part 288 governs outside and affiliate rate case expenses for which recovery is sought by the utility through rates. 83 Ill. Admin. Code 288.10. IAWC also supplied the information required by that rule, related to its current rate case expenses. *See* 83 Ill. Admin. Code 288.40(a).

As required by Part 288, IAWC provided in discovery (and in its direct case) this information to assist Staff and other parties in developing a recommended amount of rate case expense:

- requests for production, engagement agreements, and direct testimony describing the terms of engagement between IAWC and outside counsel and technical experts, including their support staff, which describe the nature of the services to be provided, by whom, the attendant hourly rates, and whether specific overhead expenses are excluded from those rates, 83 Ill. Admin. Code 288.30(a)(1), (d); (IAWC Exs. 4.00 at 32-45; 4.00R at 9; 4.00SR at 13; 15.01SR at 3-43, 112-13);

- for outside counsel services, which were provided under hourly rate contracts, invoices that clearly indicate the services provided, who provided them, the time spent providing them, and the applicable hourly rates, 83 Ill. Admin. Code 288.30(a)(2); (IAWC Ex. 15.01SR at 91-107, 297-312, 349-64, 380-406, 409-38);

- for outside technical expert services, which were provided under hourly rate contracts, some of which included a not-to-exceed component,[23] invoices that clearly indicate the services provided, who provided them, the time spent providing them, and the applicable hourly rates, 83 Ill. Admin. Code 288.30(a)(3); (IAWC Ex. 15.01SR at 44-80, 108-10, 114-296, 315-48, 367-79, 407-08, 439-47); and

- for American Water Works Service Company services, documentation that describes the services provided, the employee number and title of the persons providing those services, the time spent providing the services on a daily basis, the hourly rates, without gross-up for benefits, like performance pay, and the

[23] IAWC did not use flat fee contracts. *Cf.* 83. Ill. Admin. Code 288.30(a)(4), (5).

resultant total amounts charged, 83 Ill. Admin. Code 288.30(a)(6); (IAWC Exs. 15.02SR; 15.03SR at 8, 30, 60; 4.10SR).

IAWC also provided with its direct case:

- the information required by 83 Illinois Administrative Code 285.3085 (Schedules C-10 and C-10.1), 83 Ill. Admin. Code 288.30(b)(1); (IAWC Ex. 4.00 at 19-21);

- explanations of the processes, procedures, and controls IAWC uses to ensure that (a) work performed by outside professionals does not duplicate the work of IAWC personnel, and (b) bills from outside professionals are accurate, reasonable, and not redundant, before payment is made, 83 Ill. Admin. Code 288.30(b)(3)-(4); (IAWC Ex. 4.00 at 34, 37-38, 40-43);

- explanations of the reasonableness of the fees to be paid to outside professionals, considering factors enumerated in 83 Illinois Administrative Code 288.40, such as the nature and extent of the work required, the skill required to perform that work, and the professionals' credentials, 83 Ill. Admin. Code 288.30(b)(5), 288.40; (IAWC Ex. 4.00 at 29-45); and

- the rationale for IAWC's proposed two-year amortization period—the Company's historical rate case frequency and the effect on rate case timing of the Commission's order in Docket 15-0017, the rulemaking to amend 83 Illinois Administrative Code, Part 656, "Qualifying Infrastructure Plant Surcharge," 83 Ill. Admin. Code 288.30(b)(6); (IAWC Ex. 4.00 at 19-20).

IAWC also provided with its direct, rebuttal, and surrebuttal cases summary schedules of its rate case expenses, which showed the total projected, total incurred, and total remaining rate case expenses for each professional. 83 Ill. Admin. Code 288.30(c)(1)-(4); (IAWC Exs. 4.03 (Rev.); 4.12R; 4.10SR; 15.02SR; 15.03SR.) IAWC Exhibit 4.10SR also indicates where in IAWC's discovery responses the invoices supporting each expense incurred to date can be found. (IAWC Ex. 4.10SR. *See also* IAWC Exs. 15.01SR-15.03SR (collecting those responses).)

On July 19, 2016, consistent with Part 288, IAWC filed the Affidavit of Rich Kerckhove, attesting that the compensation paid or to be paid by IAWC to outside and affiliate professionals for their rate case work is supported by billings or other documentation that are true and accurate; support costs that were reasonable to prepare and litigate the rate case; were reviewed and approved by IAWC management prior to payment; and are not duplicative. (IAWC Ex.

14.00SR.) Mr. Kerckhove also attested that IAWC has paid, or will pay, the billed amounts for which IAWC requests rate recovery as rate case expense. 83 Ill. Admin. Code 288.30(e)(1)-(3); (IAWC Exs. 14.00SR; 4.00SR at 15).

Finally, as explained and as required by Part 288, IAWC submitted all of its rate case expense support—including testimony, summary schedules, outside professional requests for proposals, engagement agreements, invoices, and discovery responses—for the evidentiary record to aid the Commission's assessment of the expense. 83 Ill. Admin. Code 288.30(f); (IAWC Exs. 4.00SR at 12-13; 4.11SR; 15.01SR; 15.02SR; 15.03SR). Additionally, the work product of the professionals that performed the rate case work, including IAWC's testimony, exhibits, and legal filings on the Commission's e-Docket system, further support the justness and reasonableness of IAWC's rate case professionals' expenses.

In light of the surfeit of record evidence that IAWC has supplied supporting the justness and reasonable of its rate cases expenses, the Company's compliance with Part 288, the recommendation of Staff regarding IAWC's rate case expenses, and the agreement of the parties, the Commission should approve IAWC's requested $2,829,388 level of rate case expense.

11. Unamortized Docket 09-0319 Rate Case Expense

IAWC originally requested recovery of unamortized, unrecovered Docket 09-0319 rate case expense inadvertently omitted from Docket 11-0767. (IAWC Ex. 4.00 at 20.) Staff witness Kahle and AG witness Effron opposed recovery of the expense, and proposed an adjustment to remove it from the revenue requirement. (ICC Staff Ex. 3.0 at 4; AG Ex. 1.0 at 20.) To narrow the issues in this case, IAWC accepted that adjustment. (IAWC Ex. 4.00SR at 7.)

12. Long-Term Performance Plan Expense

Like the overwhelming majority of its peers (93%), IAWC awards long-term performance pay to attract and retain the critically skilled employees needed to run its business, and to focus those employees on the long-term financial success of the Company. (IAWC Exs. 9.00 at 10; 9.01 (Rev.) at 8-9; 7.00R (Rev.) at 26. *See also* ICC Staff Ex. 3.0, Attach. G at 17-38 (plan document).)

IAWC firmly believes that customers benefit when their utility is financially healthy, because this mitigates the costs that customers ultimately pay through rates. (*See* IAWC Ex. 7.00R (Rev.) at 21-36.) For example, financial success demands attention to operating efficiency; that is, unless the utility controls or reduces its costs, it cannot achieve earnings per share or other financial goals. (*Id*. at 24.) And a financially healthy utility can secure the debt capital that it needs to operate at reasonable costs. (IAWC Exs. 7.00R (Rev.) at 26; 2.00 at 23.)

For these reasons—and because its employees' total compensation, which may include long-term performance pay, is prudent and reasonable (*see supra* § VI.A.2.a)—IAWC initially requested recovery of its test year Long-Term Performance Plan expense in this case. However, to narrow the issues in this case, and without waiving its right to seek recovery of long-term performance pay costs in future proceedings, IAWC no longer seeks recovery of the expense here. (IAWC Ex. 7.00SR (Rev.) at 10-11.) IAWC has accepted Staff's proposed adjustment to its Long-Term Performance Plan expense, as corrected by Staff in discovery. (*Id*.; IAWC Ex. 4.00SR at 6-7; IAWC-Staff Stip. Cross Ex. 1.00 at 17, 19.)

C. Recommended Operating Revenues and Expenses

On a Total Company basis, the base rate revenue requirement is $269,909,873, meaning additional annual revenue of $42,526,413 is needed to afford IAWC the opportunity to earn a reasonable rate of return, as shown on IAWC Exhibit 4.01SR (Rev.). The operating income statement for each Rate Area is shown on pages 2-5 of IAWC Exhibit 4.01SR (Rev.).

V. RIDERS

A. Contested Issues

1. Rider VBA

The Commission, and the Illinois Supreme Court, have found that decoupling a utility's sales and revenues—by truing up rates to approved revenues—addresses the cost recovery problems posed by declining or variable usage for utilities whose costs are mostly fixed. IAWC has both declining and variable usage, and most of its costs are fixed. IAWC's proposed decoupling mechanism, Rider VBA, is therefore an appropriate tool to address the effect of this—with benefits to both IAWC and its customers.

IAWC's Rider VBA is a tariff modeled after the Rider VBA first approved by the Commission for the Peoples Gas Light and Coke Company and North Shore Gas Company (Peoples/North Shore) in 2008. *See N. Shore Gas Co., et al.*, Dockets 07-0241/0242 (cons.), Order at 150 (Feb. 5, 2008). IAWC's proposal is supported by Commission Staff, and adoption of Rider VBA is not opposed by IIWC[24] or AG witness Rubin. (ICC Staff Ex. 8.0 at 2; *see generally* AG Ex. 2.0 at 12-16.)

The basic methodology for IAWC's Rider VBA, if adopted, is also not in dispute. Rider VBA would compare the rate case authorized amount of volumetric revenues to actual volumetric revenues, net of production expenses (power, chemicals, and water waste disposal) that vary directly with sales levels, and provide a credit (if revenues exceed the authorized level) or a volumetric surcharge (if revenues are below the authorized level). (IAWC Ex. 7.00 at 11-12.) Netting production costs will ensure that customers pay only those production costs for the actual amount of water delivered. (*Id.* at 12.)

[24] In communications on August 26 and 27, 2016, counsel for IIWC informed counsel for IAWC that IIWC will not oppose Rider VBA.

As it did for the gas utilities, Rider VBA would resolve for IAWC serious concerns about declining and variable sales. Like the gas utilities, most of IAWC's costs are fixed, and do not vary with usage. (*Id.* at 4-5.) Under traditional ratemaking, however, IAWC relies on volumetric charges (which are based on the number of gallons of water a customer consumes), to recover the majority of its costs. (*Id.* at 5.) Thus, IAWC's cost recovery is heavily dependent on water sales volume. (*Id.*) Declining usage, weather, or both, can push IAWC's sales volumes, and so revenues, below the point where the utility has a reasonable opportunity to recover its costs. (*Id.*)

Decoupling resolves these concerns by producing a determined amount of revenue regardless of how much water (or energy) a utility delivers, and so ensuring the utility can recover its Commission-authorized revenue requirement. IAWC thus proposed to adopt Rider VBA to true up IAWC's volumetric revenues (net of sales-related production costs) to their authorized level. IAWC's proposed Rider VBA follows Illinois' established decoupling approach and benefits both the utility and its customers.

a. Revenue decoupling is a well-established Illinois regulatory mechanism for addressing the problem of fixed cost recovery through usage dependent charges.

Revenue decoupling in Illinois is not new. The Commission first considered a Rider VBA decoupling mechanism over eight years ago, when it approved Rider VBA for Peoples/North Shore on a pilot basis in Dockets 07-0241/0242. *N. Shore Gas Co., et al.*, Dockets 07-0241/0242 (cons.), Order at 150. And even at that time, the Commission noted that the concept of a regulatory mechanism designed to address "usage patterns and margin recovery fluctuations" was not novel. *Id.*

The Commission has since made the Peoples/North Shore Rider VBA permanent, *see N. Shore Gas Co., et al.*, Dockets 11-0280/0281 (cons.), Order (Jan. 10, 2012). The Illinois

Supreme Court upheld the Commission's Order in Dockets 11-0280/0281 in January 2015, finding that the Rider VBA mechanism was legal. *People ex rel. Madigan v. Ill. Commerce Comm'n*, 2015 IL 116005 (holding that Rider VBA did not violate either the prohibition against single-issue ratemaking or the rule against retroactive ratemaking). And the Commission has since recently approved a Rider VBA for Ameren Illinois Company. *Ameren Ill. Co.*, Docket 15-0142, Order at 109 (Dec. 9, 2015).

i. The Commission has approved Rider VBAs to address concerns about declining usage and usage that varied due to weather.

In Dockets 07-0241/0242, Peoples/North Shore explained that a very large percentage of their costs are fixed, and a significant portion of fixed costs will be recovered through volumetric distribution charges. Thus, cost recovery would vary with changes in consumption due to "conservation measures, warming weather trends, the involvement of the Utilities in gas efficiency programs, and other events." *See N. Shore Gas Co., et al.*, Dockets 07-0241/0242 (cons.), Order at 126, 136, 138-39. Rider VBA was thus proposed "to remove both the incentive utilities have to increase sales and the disincentives that utilities have to encourage energy efficiency for their customers." *Id.* at 126.

The Commission adopted Rider VBA as a pilot, finding "it reflects the particulars of declining and variable customer usage patterns and the concomitant revenue recovery impacts." *Id*. at 150. Otherwise, improvements in efficiency would actually harm the utility: "efficiency strategies and improvements, by their very nature, will worsen the Utilities' ability to recover margin revenues in the immediate future. Furthermore, unlike simple conservation activities, efficiency improvements have more long-term sustained effects." *Id.* at 151.

Four years later, the Commission relied on similar reasoning to make Rider VBA permanent for Peoples/North Shore, in Docket 11-0280. *N. Shore Gas Co., et al.*, Dockets 11-

0280/0281 (cons.), Order at 163. The Commission found that "decoupling means that customers do not overpay when weather is colder than normal or underpay when weather is warmer than normal. Decoupling also addresses load changes, including declining load attributable to energy efficiency." *Id.* at 164. Additional benefits included a reduction in the reliance on forecasting customers and usage to set rates. *Id.* at 163.

Later in 2015, Ameren Illinois Company proposed, and the Commission approved, a Rider VBA similar to Peoples/North Shore's Rider VBA. No party in that case objected to the rider's adoption, and it was approved as an uncontested issue. *Ameren Ill. Co.*, Docket 15-0142, Order at 109.

ii. The Illinois Supreme Court has affirmed that the Rider VBA decoupling mechanism is lawful.

The Commission Order making Peoples/North Shore Rider VBA permanent was appealed, ultimately to the Illinois Supreme Court. The Supreme Court affirmed the Commission's approval of Rider VBA and the legality of the revenue decoupling mechanism. *People ex rel. Madigan*, 2015 IL 116005. In so doing, the Supreme Court recognized three fundamental aspects of the Rider, each of which applies to IAWC's Rider VBA here. *Id.*

First, Rider VBA eliminated concerns about utility cost recovery in the face of declining usage:

> The rider helps the companies bridge the increasingly problematic disconnect between their fixed costs and their revenue losses due to a diminishing customer base and aggressive energy efficiency programs. It also guards the customers against the negative effects of inevitably incorrect forecasting. Decoupling stabilizes both utility revenues and customer bills.

Id. ¶ 33.

Second, Rider VBA eliminated "perverse" incentives to increase sales:

> Before Rider VBA, the companies recovered their fixed distribution costs through volumetric charges, which meant that the revenue they collected from those

> charges was either higher or lower than the revenue requirement, depending on how much gas that their customers used. Such a rate design created perverse incentives for the companies to increase demand or under-forecast usage. . . . Rider VBA accepts the revenue requirement and offers a way for the companies to recover it—no more or less—via the annual true-up calculation.

Id. ¶ 32.

And third, Rider VBA provided an incentive to utilities to manage their costs:

> Under this rider, the amount of revenue that the company can recover is capped, regardless of its actual costs. If those costs increase beyond the amounts used to calculate the revenue requirement, the companies' profits will decrease. Rider VBA does not allow them to earn more than that to which they are already entitled. It does, however, encourage them to manage their business effectively, so the revenue requirement not only covers their costs, but also ultimately provides a reasonable return.

Id.

The Court concluded that because Rider VBA accepts the revenue requirement and provides a mechanism to recover it accurately, it has no impact on the revenue requirement and so poses no risk of distorting the ratemaking process. *Id.* ¶ 40.

b. Like the gas utilities, IAWC has high fixed costs but experiences both declining usage and weather variability, with the same adverse impact on cost recovery.

Approximately 93% of IAWC's costs are fixed. But only approximately 39% of its revenues are fixed; approximately 61% are variable. (IAWC Ex. 7.00 at 6.) IAWC, therefore, relies heavily on variable (or volumetric) revenues for collecting fixed costs. (*Id.* at 7.) Because IAWC is so dependent on volumetric sales for revenue, it is incented to sell more water and penalized if it promotes the more efficient use of resources. (*Id.*) This rate design creates a "throughput incentive": the more water customers use, the more revenue the Company collects and, to the extent this revenue exceeds variable costs, the better its financial performance. (*Id.*)

Over the last decade, IAWC's investment has shifted largely from plant needed for serving new customers to non-revenue producing infrastructure replacement and compliance with new drinking water standards. (IAWC Ex. 3.00 at 4.) At the same time that investment is shifting away from new customers, however, both weather and declining usage per customer cause IAWC's sales volumes and revenues to vary from Commission-approved levels. (IAWC Ex. 7.00 at 7-8.)

For these reasons, IAWC has seen a continued and persistent trend of declining usage per customer. Residential usage per customer is steadily declining. (IAWC Ex. 8.00R (Rev.) at 10.) This decline in customer usage has a substantial effect on IAWC's actual sales volumes, and so on its revenues. (IAWC Ex. 7.00 at 8.) As Staff witness Brightwell explained, "[w]hether or not test year forecasts are accurate, problems occur in years beyond the test year if sales continue to decline. . . . If sales continue to decrease, then fixed costs recovered through volumetric charges will lead to an under recovery of costs in out years." (ICC Staff Ex. 8.0 at 4:84-90.)

Weather variability also affects IAWC because a water rate design that relies heavily on sales volumes means that revenues are greater when the weather is hot and dry and less when the weather is wet and cool. (IAWC Ex. 7.00 at 7-8.) Therefore, lower revenues in a cool, wet summer can exacerbate the declining usage trend. (*Id.*)

That IAWC experiences both declining usage and weather variability is not disputed: Staff witness Brightwell recognized that sales are declining, and the potential for sales variability caused by conservation efforts and weather. (ICC Staff Ex. 8.0 at 3-5.) IIWC/FEA/CUB witness Gorman also acknowledged that sales are declining. (IIWC/FEA/CUB Ex. 2.0 at 3.)

The net effect of declining usage and weather variability is that IAWC's revenue is decreasing. Over the course of the last eight calendar years, IAWC has not recovered the authorized revenues approved in its rate cases. (IAWC Ex. 8.00 at 16.) This constrains IAWC's ability to make necessary investments in its facilities. (IAWC Ex. 7.00 at 5.) Water utilities operate their source of supply, treatment, and transmission and distribution systems to provide water service to a customer's premises no matter how much water is used. (*Id.*) This requires a significant infrastructure to provide and deliver water to customers, to provide customer service, and to administer accounting and billing systems, among other critical internal and external services. (*Id.*) However, if most revenues come from sales volumes, and revenues are declining (due to declining usage, weather, or both), then the utility may be faced with sales volumes, and so revenues, too low to allow the utility to recover its costs. (*Id.*)

The reductions in water sales are therefore a significant concern: when sales volumes decline, volumetric charges do not produce enough revenue to recover fixed costs. (*Id.*) Declining and variable usage become a source of fiscal stress for IAWC, and are a potential disincentive to further investment in water efficiency. (*Id.* at 8.) IAWC is proposing to resolve these concerns through adoption of Rider VBA.

c. Rider VBA resolves the concerns with declining and variable usage while providing customer benefits.

To resolve the concerns above, IAWC proposed a tariffed decoupling mechanism that is designed to ensure IAWC collects the revenues authorized by the Commission, independent of changes in sales volume. (IAWC Ex. 7.00 at 8.) Rider VBA compares IAWC's actual volumetric revenues with authorized volumetric revenues, net of sales-related production costs, and trues up the actual revenues to the authorized amount through a credit to customers (if revenues exceed the authorized level) or a volumetric surcharge (if revenues are below the authorized level). (IAWC Exs. 7.01SR, 7.02SR.) This lets prices flow up or down as sales volume changes in between rate cases but holds revenues at authorized levels. (IAWC Ex. 7.00 at 9.)

Rider VBA removes the incentive to sell more water and any disincentive to promote water efficiency, reduces the adverse impacts of weather variability for both IAWC and its customers, and supports revenues for programs and investments that improve water efficiency. (*Id.* at 10.) Rider VBA also allows for periodic adjustments (credits and surcharges) in between rate cases, and so should reduce rate case frequency. (*Id.* at 11.) Under conventional ratemaking, in an environment of falling sales, a utility will suffer revenue erosion in between rate cases that will prompt more frequent rate cases. (*Id.*) With Rider VBA, IAWC would not need to file frequent rate cases to recover revenue shortfalls resulting from declining sales. (*Id.*) Customers benefit from a reduction in contested issues in rate cases, a reduction in the frequency of rate cases, and as a result, reduced rate case expense. (*Id.*) And, on the other hand, when IAWC does experience sales growth, it will credit the revenue in excess of the authorized amount back to its customers. (*Id.*)

d. The basic methodology and formula for Rider VBA is not in dispute; only the AG has contested proposals about where to apply the Rider.

In surrebuttal, IAWC agreed to Mr. Brightwell's formula for Rider VBA, which limits the rider's production cost netting adjustment to those changes in production costs that occur due to deviations from sales forecasts, and which recovers only volumetric revenues through Rider VBA. (IAWC Ex. 7.00SR at 2.) IAWC also agreed to various changes to the Rider VBA tariff proposed by Staff witness Hathhorn. (IAWC Ex. 7.00R (Rev.) at 3-4.) IIWC has indicated that it does not oppose adoption of Rider VBA using Staff's methodology. IAWC Exhibits 7.01SR and 7.02SR set forth the tariffs to match this agreed methodology.

AG witness Rubin also accepted Mr. Brightwell's proposed methodology, subject to two proposals, discussed below, about the Rate Zones Rider VBA should apply in. IAWC opposes these proposals. (IAWC-AG Stip. Cross Ex. 2.00 at 1.)

i. AG witness Rubin's proposal to have a separate Rider VBA for purchased water areas should be rejected.

Mr. Rubin first proposed to have a separate Rider VBA for purchased water areas. But this will cause the rider to become administratively burdensome. Separating out purchased water districts would create at least three Rider VBA calculations: Zone 1 without Chicago Metro Lake and South Beloit, Chicago Metro Lake, and South Beloit. (IAWC Ex. 7.00R (Rev.) at 8.) By adding additional groups, the preparation of the filings and costs to track expenses and revenues will increase, and audits and reviews by the Commission's Staff likewise will increase in time and therefore cost. (*Id.* at 8-9.)

Also, the Commission has approved Rate Zone 1 to be a consolidated rate zone. *See Ill.-Am. Water Co.*, Docket 11-0767, Order at 150-52 (Sept. 19, 2012). Attempting to now separate purchased water areas moves in a direction contrary to consolidation. (*Id.* at 9.) The purchased water areas have production costs that are not recovered through the purchased water rider, so these areas are no different from a rate consolidation perspective than others in the consolidated rate area. (*Id.*) And to separate them out would effectively undo the consolidation of these areas into Zone 1. (IAWC Ex. 7.00SR (Rev.) at 5.) And there would be little point to this exercise—there is not a significant difference in customers' bills from separating out purchased water customers. (*Id.* at 7-8.)

ii. AG witness Rubin's proposal to exclude Chicago Metro Wastewater from Rider VBA should be rejected.

IAWC's sewer rate area faces the same issue as its water rate areas: fixed revenues do not recover the full amount of fixed costs, so fixed cost recovery is still dependent on usage volumes. (IAWC Ex. 7.00R (Rev.) at 13.) In the Chicago Metro Wastewater district, 92% of the costs are fixed. (*Id.*) However, fixed wastewater revenues proposed in this case are only 81.8%. (*Id.*)

Since the fixed costs are not recovered by the fixed revenues, a Rider VBA is needed here to ensure the Company recovers the fixed costs of service. (*Id.*)

Leaving the wastewater district out of Rider VBA could compound the issue of declining usage too. (*Id.*) If customers conserve water or usage otherwise declines, less wastewater is billed. Therefore, IAWC would not be able to recover the fixed costs for either water or wastewater without the Rider VBA. (*Id.*) Mr. Rubin's proposal to exclude Chicago Metro sewer from Rider VBA should be rejected.

The overwhelming majority of IAWC's water and wastewater costs of service are fixed. IAWC recovers those costs mostly through volumetric revenues. This is a problem for IAWC, in light of recent declining usage, increased water conservation, and weather. Rider VBA solves that problem, because it decouples IAWC's revenues from its sales in a way that benefits both IAWC and its customers. The Commission and the Illinois Supreme Court have already concluded that such a decoupling mechanism is the appropriate means of addressing utility usage that doesn't cover utility fixed costs. The Commission should do that again here. It should approve IAWC's proposed Rider VBA tariff, as agreed by Staff and IAWC.

B. Resolved Issues

1. Pension/OPEB Rider

IAWC initially proposed a rider to recover pension OPEB costs, which may fluctuate greatly for reasons outside IAWC's control and are difficult to predict, to protect both IAWC and its customers from those wide cost variations. (IAWC Ex. 1.00 (Rev.) at 18; *see also* IAWC Exs. 7.00 at 20-25; 7.00R (Rev.) at 17-21.) To narrow the issues, however, IAWC withdrew this proposed rider. (IAWC Ex. 7.00SR (Rev.) at 10.) IAWC reserves the right to propose a Pension/OPEB rider in future cases. (*Id.*)

2. Rider QIP Recommendation

IAWC included in its rate base investments that would qualify as Qualifying Infrastructure Plant (QIP) under the Commission's Part 656 Rules, 83 Ill. Admin. Code, Part 656, effective at the time of IAWC's January 2016 direct case filing. In discovery, it provided these QIP amounts by rate zone, including accumulated depreciation, cost of removal less salvage, and depreciation expense. (ICC Staff Ex. 2.0, Attach. A.) Staff witness Hathhorn testified that it's possible that that information may be needed in future QIP reconciliation proceedings or other matters. (*Id*. at 6.) Ms. Hathhorn thus proposed that the information, which she attached as Attachment A to her direct testimony, be attached as an appendix to the Commission's final order in this case. (*Id*.) IAWC agreed with Ms. Hathhorn's proposal, with the caveat that the information in Attachment A was based on the Commission's Part 656 Rules effective in January 2016; if new rules are approved, that information would no longer be accurate. (IAWC Ex. 4.00R at 5.) The Commission revised its Part 656 Rules effective July 1, 2016. *See* 83 Ill. Admin. Code, Part 656; *Aqua Ill., Inc., et al.*, Docket 15-0017, Order (June 29, 2016).

VI. RATE DESIGN AND COST OF SERVICE

A. Contested Issues

1. Purchased Power Cost Allocation

In its cost of service study, IAWC allocated its purchased power costs using Factor 1, which is based on average daily usage. (IAWC Ex. 11.00R at 6-7.) IIWC/FEA witness Collins proposed that IAWC's purchased power costs should be allocated using Factor 6, which is based on maximum day and hour demands. (IIWC/FEA Ex. 1.0 at 17; *see also* IAWC Ex. 11.00 (Rev.) at 7 (describing Factor 6).) Mr. Collins argued that Factor 6 allocation is appropriate because that factor "recognizes the base and extra capacity components of purchased power costs, and is consistent with the allocation of IAWC's other pumping expenses and the allocation of rate base associated with electric pumping equipment." (IIWC/FEA Ex. 1.0 at 17:335-37.) Both of Mr. Collins's arguments fail.

Contrary to Mr. Collins's first assertion, Factor 6 does not accurately account for the base and extra capacity components of IAWC's purchased power costs. Electric rates are structured to include three components: a customer charge, a demand charge, and commodity charges. (IAWC Ex. 11.00R at 7.) The American Water Works Association Manual provides that "the demand portion of power costs should be allocated to extra capacity to the degree that it varies with the demand pumping requirements." (*Id*. at 7.) IAWC's electricity bills include a demand charge, even when the Company is at its lowest demand for power. (*Id*. at 7.) This is the base component of IAWC's purchased power costs. The extra capacity component of IAWC's purchased power costs is the amount by which the demand charge varies with the demand pumping requirements. (*Id*. at 7.) IAWC witness Herbert determined that only 1.25% of IAWC's total purchased power expense is attributable to extra demand. (*Id*.) If Factor 6 was applied to purchased power costs, as Mr. Collins proposes, 42.6% of IAWC's power costs would be allocated to extra demand. (*Id*.) Thus, the application of Factor 6 clearly does not accurately account for the base and extra capacity components of IAWC's electric demand costs.

Second, even though Factor 6 is used to allocate non-power pumping costs, it is not an appropriate allocator for purchased power costs. First, purchased power is conceptually similar to other costs allocated using Factor 1, such as purchased water, treatment chemicals, and sewer disposal. (IAWC Ex. 11.00 (Rev.) at 6.) Second, Factor 6 is appropriate for the "capital and associated O&M costs because the system is designed to meet average demand and as well as maximum day and hour demands." (IAWC Ex. 11.00R at 6:130-32.) However, unlike the capital and O&M costs, the power that runs the pumping facilities "varies with the amount of water being pumped, and varies *only minimally* with peak usage." (IAWC Ex. 11.00R at 7:134-35.) Because purchased power varies only minimally with peak usage, Factor 1, which is based on average daily consumption, is a more reasonable and appropriate allocator.

Thus, neither of Mr. Collins's stated bases for his proposal to use Factor 6 rather than Factor 1 withstands scrutiny. Factor 6 does not accurately reflect base and extra capacity components of IAWC's electric demand costs. And power costs do not vary significantly with maximum water demand, so they should not be treated like other pumping expenses. The Commission should reject Mr. Collins's proposal to utilize Factor 6 rather than Factor 1.

2. Simplification of Metered Large User Water Tariff

IAWC's Metered Large User water tariff is available to customers that use at least 187 million gallons of water per year. (ILL.C.C. No. 24, Sec. 1, Eight Rev. Sheet 14.1.) Charges to customers under the tariff are equal to the customer's maximum day demand ratio, multiplied by approximately $0.19. (*Id.*) The maximum day demand ratio is the customer's maximum day demand divided by the customer's average day demand. (*Id.*) The maximum day demand ratio serves two important purposes. First, it incentivizes customers to smooth their demand so that their maximum day demand is as close as possible to their average day demand, because it increases charges when the maximum demand is higher than average demand. (IAWC Ex. 11.00SR at 8.) A customer whose maximum day demand is close to its average day demand requires less extra capacity and peak facilities, so smooth demand means that the utility must invest less in these costly facilities. (*Id.*) The incentive is particularly appropriate for customers taking service under the Metered Large User tariff, because those customers must use at least 187 million gallons per year to qualify for the tariff. (*Id.*) Second, the maximum day demand ratio variable in the current tariff ensures that customers' rates are determined individually, and customized to match their usage. (*Id.*)

In his direct testimony, IIWC/FEA witness Collins proposed that IAWC's Metered Large User water tariff "should be simplified … to provide more cost certainty to customers" served under the tariff and attract additional customers to the tariff. (IIWC/FEA Ex. 1.0 at 18:361-66.) However, throughout the proceeding, Mr. Collins has not offered a substantive suggestion as to how the tariff should be simplified, nor has Mr. Collins explain why such simplification is desirable. The Commission should reject IIWC/FEA's unsupported recommendation.

At no point during this proceeding has Mr. Collins explained exactly how the "simplified" tariff he proposes would differ from IAWC's current tariff. Mr. Collins's original proposal was that "rate formula [should] be eliminated … and the rate simply be based on the utility's cost of providing service to customers served under this tariff." (IIWC/FEA Ex. 1.0 at 18:361-63.) Although Mr. Collins did not specify which portion of the existing formula he proposed to eliminate, IAWC witness Herbert surmised that Mr. Collins's concern is rooted in the fact that the current tariff includes a variable for customers' Maximum Day Demand Ratio. (IAWC Ex. 11.00SR at 7.) As discussed above, the maximum day demand ratio serves important purposes, provides appropriate incentives, and should not be eliminated.

Mr. Collins now appears to have backed away from that proposal. When IAWC requested that IIWC/FEA provide an explanation or calculation of its proposed simplification in discovery, Mr. Collins responded that he had not "recommended a specific rate design, but proposes that a specific cost-based rate design be developed cooperatively" by IAWC and IIWC/FEA. (*See* IAWC Ex. 11.00R at 8.) Then, in his rebuttal testimony, Mr. Collins suggested that the Commission order the parties in this case to participate in a workshop "to discuss possible revisions to this tariff." (IIWC/FEA Ex. 2.0 at 6:101-102.) As a result, there is no substantive proposed "simplification" that the Commission can approve in its order. Nor is there any reason to hold a workshop on this matter, since IIWC/FEA have not made a specific, substantive suggestion in this proceeding.

Finally, the rationale IIWC/FEA offers in support of its proposed simplification is illogical. Mr. Collins noted that only two customers currently take service under the Metered Large User tariff (IIWC/FEA Ex. 1.0 at 18), and stated that simplifying the tariff would be beneficial because it would "attract additional customers to take service under this tariff." (IIWC/FEA Ex. 2.0 at 6:102.) If Mr. Collins's proposal to charge Metered Large User customers based on cost of service rather than a rate formula is adopted, and is successful in attracting additional customers to the tariff, there may well come a point at which it is more efficient to use a formula than to calculate rates at the cost of service. (IAWC Ex. 11.00R at 8-9.) But IAWC's current tariff already utilizes a rate formula. There is no need to make unspecified, unsupported changes to the tariff.

3. Customer Records, Collection Labor, Uncollectible Accounts

AG witness Rubin recommended that customer accounts and uncollectibles expenses be recovered via volumetric charges, rather than fixed customer charges, (AG Ex. 2.0 at 8), so that residential customers would contribute "an equivalent percentage of their bill to support billing, collections, and uncollectible accounts," rather than an equal dollar amount. (AG Ex. 4.0 at 6:120-21.) Mr. Rubin argued that, although "there is no single 'right way' to collect these funds from customers," his methodology "is fairer to all residential customers." (*Id*. at 133.)

Mr. Rubin is incorrect—his proposal to recover customer accounts and uncollectibles expense via equal percentages of customers' bills, rather than equal dollar amounts, is not fairer to customers because "there is no difference in the cost to generate and collect a water bill for

$40, and the cost to generate and collect a water bill for $80 (or $100, $500, or $1000)." (IAWC Ex. 11.00SR at 3:45-47.) IAWC incurs customer accounts and uncollectibles expenses on a per-bill basis, not based on the dollar amount of the bill. But the AG's proposal would result in a customer with an $80 water bill paying *double* the amount of collections and uncollectibles expense that a customer with a $40 water bill would pay, even though the underlying costs to the Company are the same. (*See* IAWC Ex. 11.00SR at 4 (detailing a cost-comparison calculation).) Thus, the AG's proposal would cause higher-use customers to subsidize lower-use customers with respect to collections and uncollectibles expenses. (*Id.*) Mr. Rubin failed to explain why this subsidy is just and reasonable, or why it is "fairer." Simply put, it's not. The Commission should reject Mr. Rubin's proposal.

4. Zone 1 5/8 Meter Charge

As a corollary to his proposed adjustment for customer records, collection labor and uncollectible accounts expenses, discussed above, AG witness Rubin proposed an additional adjustment to set the customer charge for Zone 1 customers with 5/8-inch meters to no more than $18.50. (AG Ex. 2.0 at 11; *see supra* § VI.A.3.) Mr. Rubin arrived at this figure by removing the customer records, collection, and uncollectible accounts expenses from IAWC's proposed customer charge. (AG Ex. 2.0 at 8.) For the reasons explained above, his proposal to remove these expenses from the customer charge should be rejected. Mr. Rubin offered no compelling support for his proposal to set the customer charge to $18.50. As a result, the Commission should reject that proposal as well.

5. Limitation of Increase by Class

AG witness Rubin proposed that rate increases for all customer classes should be limited so that no class receives an increase of more than 1.5 times the system-average increase, and no class receives an increase that is less than 0.5 times the system-average increase. (AG Ex. 2.0 at

10.) Mr. Rubin based this proposal on the ratemaking principles of gradualism and rate continuity. (*Id.*) Although IAWC agrees that, generally, rate increases should be gradual and continuous, and that the 0.5 – 1.5 times system average increase limitation is generally reasonable, the Company cannot accept Mr. Rubin's proposal to apply this limitation to all customer classes. (IAWC Ex. 11.00R at 12.) Applying this limitation to all rate classes would result in increases to customers that are served under contract. (*Id.*) IAWC's contractual rates are fixed in the contracts, which provide the specific provisions for how the rate can be increased. They simply do not allow for the increases Mr. Rubin proposes.

The overall increase in IAWC's rates is approximately 21.6%. (IAWC Ex. 11.01 (Rev.) at 114.) Therefore, under Mr. Rubin's proposed limitations, no class would receive a rate increase of less than 10.8% or more than 32.4%. (AG Ex. 2.0 at 10.) But in applying these limitations, Mr. Rubin did not account for IAWC's limited ability to increase rates for the customer classes served under contract: the Large Commercial, Competitive Industrial, and Large Other Water Utility customer classes. The table below compares IAWC's rate increase for the contractual customer classes allocation against Mr. Rubin's:

CUSTOMER CLASS	IAWC PROPOSED % INCREASE[25]	AG PROPOSED % INCREASE[26]
Large Commercial	3.4	32.4
Competitive Industrial	0.5	32.4
Large Other Public Authority	19.3	32.4
Large Other Water Utility	5.4	32.4

Mr. Rubin's proposal would result in the maximum increase of 32.4% for the Large Commercial, Competitive Industrial, and Large Other Water Utility customer classes. (AG Ex. 2.4.) However, the rates for those classes are set by contract, and the contractual rates cannot be

[25] IAWC Ex. 11.01 (Rev.)
[26] AG Ex. 2.4.

increased as Mr. Rubin proposes. (IAWC Ex. 11.00R at 12.) The Commission should reject his proposal.

6. Demand Factors

Consistent with the Commission's directive in Docket 11-0767, IAWC conducted a direct demand study in preparation for this case, in which the Company directly measured the demand of a sample group of customers between May 2011 and October 2015. (IAWC Ex. 11.00R at 3); *see also Ill.-Am. Water Co.*, Docket 11-0767, Order at 113-14 (instructing the Company to collect demand data and update its demand factors in future rate cases). IAWC used the results of that demand study to develop the demand factors it proposed in this case. (IAWC Ex. 11.00R at 3.) Staff and AG witnesses accepted those proposed demand factors, but IIWC/FEA witness Collins recommended that the Commission ignore the results of the demand study, and rely instead on demand factors developed and approved in IAWC's last rate case, Docket 11-0767. (IIWC/FEA Ex. 1.0 at 15.) The Commission should reject Mr. Collins's proposal and approve the updated demand factors IAWC has proposed here, and which Staff and AG support.

IAWC's proposed demand factors reflect the most recent available actual data regarding IAWC customers' demand. (IAWC Ex. 11.00R at 3.) In contrast, the demand factors Mr. Collins advocates are based on very limited direct measurement data that was collected prior to the filing of IAWC's rate case in 2011. (*Id.*) In the years since Docket 11-0767, IAWC has collected more comprehensive data, and its proposed demand factors are based on that more recent, more comprehensive data. (*Id.*)

The Commission has expressed a preference for demand factors based on the most recent available data. *See, e.g., Ill.-Am. Water Co.*, Docket 09-0319, Order at 149-50 (April 30, 2010); *Ill.-Am. Water Co.*, Docket 07-0507, Order at 121 (July 30, 2008); *Ill.-Am. Water Co.*, Docket 02-0690, Order at 119-20 (Aug. 12, 2003). Mr. Collins has not offered a compelling reason to reject the more recent, more comprehensive data IAWC presented in this proceeding, or reconsider the Commission's preference for more recent data. Tellingly, Mr. Collins did not respond to IAWC's criticisms of his proposal. (*See* IIWC/FEA Ex. 2.0 at 4-7.) Therefore, Mr. Collins's proposal to utilize demand factors from Docket 11-0767 should be rejected.

B. Resolved Issues

1. Declining Block Usage Charge for Non-Residential Customers in Chicago Metro Sewer

Staff witness Boggs recommended that IAWC continue to apply a declining block usage charge to Collection Only and Collection and Treatment customer classes in the Chicago Metro Sewer District, as had been approved in prior cases. (ICC Staff Ex. 6.0 at 22.) IAWC accepted this proposal. (IAWC Ex. 11.00R at 5.) Therefore, the issue is resolved.

2. Public Fire Charges

Staff witness Boggs recommended that the Public Fire Protection rate for each of IAWC's three water districts be set so that the revenues recovered are equal to the cost to serve the respective district. (ICC Staff Ex. 6.0 at 29.) This recommendation required IAWC to increase the Public Fire Protection rates in Zone 1 and Lincoln, but decrease the rates in Pekin. (*Id.* at 29-30.) IAWC did not object to Staff's proposal. (IAWC Ex. 11.00R at 5.) This issue is therefore resolved.

3. Certain Large User

IAWC originally excluded a certain customer in the Large Industrial class from its cost of service study. IIWC/FEA witness Collins and IIWC/FEA/CUB witness Gorman recommended that the customer be included in the study. (IIWC/FEA Ex. 1.0 at 7; IIWC/FEA/CUB Ex. 1.0 at 6.) Mr. Collins stated that, although the customer's usage had "declined due to economic circumstances," the customer "did not intend to cease all operations at its facilities served by

IAWC." (IIWC/FEA Ex. 1.0 at 7:134-36.) IAWC proposed to account for the decline in the customer's usage by utilizing the customer's most recent 12-month usage level. (IAWC Ex. 4.00R at 21-22.) Mr. Collins and Mr. Gorman agreed this revised usage was reasonable. (IIWC/FEA Ex. 2.0 at 3; IIWC/FEA/CUB Ex. 2.0 (Rev.) at 2-3.) Therefore, this issue is resolved.

4. Distribution Main Allocation to Large Users

AG witness Rubin proposed to modify IAWC's Factor 4, which allocates costs associated with distribution mains for purposes of the cost of service study. (AG Ex. 2.0 at 5-7.) IAWC's proposed Factor 4 excludes usage from the Large Commercial, Large Industrial, Competitive Industrial, Large Other Public Authority, Other Water Utilities, and Large Other Water Utilities classes because generally, these customers are served from transmission mains, rather than distribution mains. (IAWC Ex. 11.00R at 11.) Mr. Rubin reviewed maps of the IAWC system and determined that eleven of the thirty-four customers excluded from the allocation of distribution main costs were served by distribution mains. (AG Ex. 2.0 at 5-7.) Therefore, Mr. Rubin added the usage from those eleven customers into his calculation of Factor 4. (*Id.*) IAWC witness Herbert also reviewed the maps of the customer connections, and determined that six of the eleven customers at issue were served by short stub distribution-diameter mains, and should not be considered connected to distribution mains. (IAWC Ex. 11.00R at 11.) However, Mr. Herbert determined that the remaining five customers could be considered served from a distribution main, and added their consumption into the calculation of Factor 4. (*Id.*) Mr. Rubin agreed with IAWC's revised Factor 4. (AG Ex. 4.0 at 7.) Therefore, the issue is resolved.

VII. CONCLUSION

For the reasons set forth in this Brief, IAWC requests the Commission authorize for IAWC a base rate revenue requirement of $269,909,873, reflecting additional annual revenue of

$42,526,413, to afford IAWC the opportunity to recover its expenses and earn a reasonable rate of return, as shown on IAWC Exhibit 4.01SR (Rev.).

Dated: August 31, 2016

Respectfully submitted,

ILLINOIS-AMERICAN WATER COMPANY,

By: *_/s/ Albert D. Sturtevant_*

One of its attorneys

Albert D. Sturtevant
Anne M. Zehr
Hanna M. Conger
WHITT STURTEVANT LLP
180 N. LaSalle Street, Suite 2001
Chicago, Illinois 60601
(312) 251-3017
sturtevant@whitt-sturtevant.com
zehr@whitt-sturtevant.com
conger@whitt-sturtevant.com

Mark A. Whitt
WHITT STURTEVANT LLP
88 East Broad Street, Suite 1590
Columbus, Ohio 43215
(312) 251-3911
whitt@whitt-sturtevant.com

Kenneth C. Jones
Vice President – Legal
Illinois-American Water Company
100 N. Water Works Drive
Belleville, Illinois 6222
(618) 239-3222
kenneth.jones@amwater.com

CERTIFICATE OF SERVICE

I, Albert D. Sturtevant, an attorney, certify that on August 31, 2016, I caused a copy of the foregoing *Initial Brief of Illinois-American Water Company* to be served by electronic mail to the individuals on the Commission's Service List for Docket 16-0093.

/s/ Albert D. Sturtevant
Attorney for Illinois-American Water Company

2016 WL 7325212 (Ill.C.C.), 334 P.U.R.4th 424
Slip Copy

Illinois-American Water Company

16-0093

Illinois Commerce Commission

December 13, 2016

ORDER

Proposed Rate Increases for Water and Sewer Service. (tariff filed on January 21, 2016)

BY THE COMMISSION:Brien Sheahan, Chairman

TABLE OF CONTENTS

I. INTRODUCTION

A. Procedural History

***1** On January 21, 2016, Illinois-American Water Company ("IAWC" or ""Company") filed revised tariff sheets ("Proposed Tariffs") with the Illinois Commerce Commission ("Commission") in which it proposed a general increase in water and sewer rates pursuant to Section 9-201 of the Public Utilities Act ("Act"). The Proposed Tariffs were identified as follows: Ill. C. C. No. 5, Seventeenth Revised Sheet No. 37, Sixth Revised Sheet No. 39, Original Sheet Nos. 39.1 & 39.2, Third Revised Sheet No. 40, Original Sheet Nos. 40.1 & 40.2, Sixth Revised Sheet No. 59; Ill. C. C. No. 24, Section No. 1, Table of Contents, Second Revised Page 1, Ninth Revised Sheet No. 1, Eighth Revised Sheet No. 1.1, Seventh Revised Sheet No. 2, Fifth Revised Sheet No. 3, Fourth Revised Sheet No. 3.1, Seventh Revised Sheet No. 3.2, Sixth Revised Sheet No. 7, Seventh Revised Sheet Nos. 7.2 & 7.3, Fifth Revised Sheet Nos. 7.4 - 7.7, Seventh Revised Sheet No. 8, Sixth Revised Sheet Nos. 11.1 & 11.2, Fifth Revised Sheet Nos. 11.4 & 11.5, Eighth Revised Sheet No. 14.1, First Revised Sheet Nos. 22 & 22.1, Original Sheet Nos. 22.2, 23, 23.1, & 23.2; Section No. 3, Table of Contents, Second Revised Page 1, Seventh Revised Sheet No. 1, Fifth Revised Sheet Nos. 2, 3, & 8, First Revised Sheet Nos. 22 & 22.1, Original Sheet Nos. 22.2, 23, 23.1, & 23.2; Section No. 4, Table of Contents, Second Revised Page 1, Sixth Revised Sheet No. 1, Fourth Revised Sheet Nos. 2 & 3, Sixth Revised Sheet Nos. 7, 7.1, 7.2, & 14.1, First Revised Sheet Nos. 22 & 22.1, and Original Sheet Nos. 22.2, 23, 23.1, & 23.2.

Simultaneous with and in support of its filing of the Proposed Tariffs, IAWC filed testimony, exhibits and schedules intended to meet the requirements of 83 Ill. Adm. Code 285, 286 and 287. Notice of the filing of the Proposed Tariffs was sent to customers, posted in IAWC's business offices, and published in a newspaper of general circulation within each of IAWC's service areas, in accordance with the requirements of Section 9-201(a) of the Act and 83 Ill. Adm. Code 255.

***2** On February 24, 2016, the Commission entered a Suspension Order suspending the Proposed Tariffs to and including June 18, 2016. Subsequently, the Commission entered a Resuspension Order on June 1, 2016 extending the suspension to and including December 18, 2016.

Appearances or Petitions to Intervene were filed by the Attorney General of the State of Illinois (the "Attorney General" or "AG"); the City of Peoria ("Peoria"); Prairie Farms Dairy, Inc., United States Steel Corporation-Granite City Works, and the University of Illinois, collectively referred to as the Illinois Industrial Water Consumers ("IIWC"); the Village of Tinley Park ("Tinley Park"); the Cities of Champaign, Urbana, and South Beloit and the Villages of St. Joseph, Savoy, Philo, and Sidney (collectively, the "Municipalities"); the Citizens Utility Board ("CUB"); the Village of Bolingbrook ("Bolingbrook"); the Federal Executive Agencies ("FEA"); and Bond-Madison Water Company ("Bond-Madison"). All of the petitions were granted.

Pursuant to due notice, hearings were held in this matter on March 22, 2016, July 26, 2016, and July 28, 2016 before duly authorized Administrative Law Judges ("ALJs") of the Commission at its offices in Chicago, Illinois. Testimony and exhibits filed by IAWC, Commission Staff ("Staff"), the AG, IIWC/FEA/CUB, IIWC/FEA, the Municipalities, and Tinley Park were admitted into evidence at the evidentiary hearing held on July 28, 2016. Thereafter, the record was marked "Heard and Taken."

Initial Briefs and Reply Briefs were filed by IAWC, Staff, the AG, IIWC/FEA/CUB, IIWC/FEA, and the Municipalities on August 31, 2016 and September 19, 2016, respectively. Various motions were filed and briefed by the parties and subsequently ruled on by the ALJs, including Staff's motions to deny requests for a public forum, which were all granted and Staff's motion to strike portions of IAWC's Initial Brief, which was denied. A Petition for Interlocutory Review of the ALJs' rulings on Staff's motions to deny requests for a public forum was filed by the Municipalities on July 12, 2016. The petition was denied.

The ALJs' Proposed Order was served on October 19, 2016. Briefs on Exceptions were filed on October 28, 2016 by IAWC, Staff, the AG, IIWC/FEA/CUB, and IIWC/FEA. Reply Briefs on Exceptions were filed on November 4, 2016 by IAWC, Staff, the AG, and IIWC/FEA/CUB. This Order considers all of the positions and arguments set forth in the Briefs on Exceptions and Reply Briefs on Exceptions.

B. Nature of IAWC's Operations

IAWC is an Illinois public utility that furnishes water and wastewater service to residential, commercial, industrial, and governmental users in its Alton, Cairo, Champaign, Chicago Metro, Hardin County, Interurban, Lincoln, Pekin, Peoria, Pontiac, South Beloit, Sterling and Streator service districts. IAWC is incorporated in Illinois and its principal office is in Belleville, Illinois. IAWC currently employs just under 500 people in Illinois, and serves approximately 310,000 customers.

***3** IAWC is a wholly-owned subsidiary of American Water Company ("American Water"), a holding company that owns the stock of regulated water and sewer utility subsidiaries operating in multiple states. American Water's service company, American Water Works Service Company, Inc. (the "Service Company") provides support services to IAWC in accordance with a Commission-approved agreement. IAWC also obtains debt financing through American Water Capital Corporation in accordance with the terms of an approved agreement.

C. Test Year

In this proceeding, the Company's proposed rate increase request is based on a future test year consisting of the 12 months ending December 31, 2017. No party objects to the use of this test year.

D. Proposed Revenue Increase

IAWC is proposing to increase annual revenues by $42,526,414 over current pro forma revenues. This proposed revenue increase reflects that IAWC agreed with or accepted, in whole or in part, numerous adjustments proposed by the parties. IAWC also updated certain items.

II. RATE BASE

A. Resolved Issues

1. Accrued Liability for OPEB

The Company agreed to reflect $1,898,284 in rate base for accrued liability for other (non-pension) post-employment benefits ("OPEB"), which represents the cumulative excess of accrued OPEB costs over actual cash disbursements for OPEB. The Commission notes that this approach is uncontested, and it will be adopted for purposes of this proceeding. IAWC 4.00R at 15; AG Ex. 1.0 at 7.

2. Capitalized Prior Performance Plan Costs

The AG proposed to remove the 2012 to 2016 capitalized costs of incentive compensation plans that were not included in the revenue requirement in IAWC's last rate case, Docket No. 11-0767. AG Ex. 1.0 at 10. IAWC accepted the portion of this adjustment that removed previously disallowed capitalized incentive compensation costs, and Mr. Effron made additional corrections to the calculation of the adjustment, as agreed by the parties in discovery. IAWC Ex. 4.00R at 16. Staff proposed adjustments to remove incentive compensation expenses that are based on underlying financial goals that primarily benefit shareholders, because ratepayers should not be required to fund incentive compensation plans linked to the financial performance goals of the Company. Staff's adjustments covered capitalized incentive compensation expenses from 2012 through the 2017 test year. Staff Ex. 3.0 at 10-14. The Company included a portion of the AG's proposed capitalized incentive compensation expense adjustment covering 2012 through 2016 in its rebuttal revenue requirement. IAWC Ex. 4.00R at 16; IAWC Ex. 4.04R (Rev.), column "f". The Company included the remainder of the AG's proposed capitalized incentive compensation expense adjustment covering 2012 through 2016 in its surrebuttal revenue requirement. IAWC Ex. 4.04SR (Rev.), column "f". The Company also included the capitalized incentive compensation expense adjustment for 2017 in its surrebuttal revenue requirement. IAWC Ex. 4.04SR (Rev.), column "l" and IAWC Ex. 4.02SR (Rev.) column "u". While Staff's calculation of the adjustment to remove capitalized incentive compensation expenses differs from the adjustments accepted by the Company, to simplify matters, Staff adopted the adjustments as presented by the Company in its rebuttal and surrebuttal revenue requirements.

***4** In light of the parties' agreement, the Commission finds that Mr. Effron's adjustment, as accepted by IAWC, corrected by Mr. Effron, and agreed to by Staff, is reasonable and approved.

3. Cash Working Capital

a. Income Available for Return on Equity in Cash Working Capital

IIWC/FEA/CUB witness Gorman proposed a correction to the amount of income available for common equity included in cash working capital ("CWC"). IIWC/FEA/CUB Ex. 1.0 at 16. Staff presented adjustments to CWC for the Company based on the Gross Lag Approach. Staff Ex. 2.0 at 3. Staff's schedules reflect adjustments to the test year revenues and expenses for Staff's revenue requirement presented in its brief. The Company agrees with Staff's use of the Gross Lag methodology and that the final balance of CWC will be established using the revenue requirement and CWC methodology that is ultimately approved by the Commission in this proceeding. IAWC Ex. 12.00R. Therefore, Staff has no methodology differences from the Company. Staff Ex. 10.0 at 3. The Company accepted IIWC/FEA/CUB's correction. IAWC Ex. 12.00R at 3. The Commission finds that this correction is reasonable and uncontested, and it is approved.

b. Tank Painting Amortization

Staff witness Hathhorn and IIWC/FEA/CUB witness Gorman proposed corrections to exclude tank painting amortization from the CWC calculations of depreciation and amortization expense and from maintenance-other expense. Staff Ex. 2.0 at 4; IIWC/FEA/CUB Ex. 1.0 at 17. IAWC accepted Staff's corrections in discovery and IIWC/FEA/CUB acknowledged that these corrections resolved their concerns. IAWC Ex. 12.00R at 3-4. The Commission notes that this approach is uncontested, and it will be adopted for purposes of this proceeding.

c. Rate Case Expense Amortization

IIWC/FEA/CUB witness Gorman proposed a correction to remove rate case expense amortization from the CWC calculation. IIWC/FEA/CUB Ex. 1.0 at 17. IAWC accepted this correction in discovery. IAWC Ex. 12.00R at 3-4. Because the parties are in agreement, the Commission adopts this approach for purposes of this proceeding.

4. Accumulated Deferred Income Taxes

a. Deferred Tax Assets for Utility Plant Acquisition Adjustment and Deferred Rate Proceedings

Staff witness Hathhorn proposed to adjust rate base to exclude accumulated deferred income taxes for two accounts that the Company acknowledged it inadvertently included in each rate zone. Accounts for Net Utility Plant Acquisition Adjustment and Deferred Rate Proceedings should not have been included in the deferred tax calculation as the associated assets and liabilities are not included in rate base. Staff Ex. 2.00 at 5. IAWC agreed to these adjustments. IAWC Ex. 4.00R at 3. The Commission finds that these adjustments are reasonable and uncontested; they will be adopted for purposes of this proceeding.

b. Restated for Change in State Income Tax Rate

Staff witness Hathhorn and AG witness Effron both accepted IAWC's proposal to use the 7.75% state income tax rate, which is based on a 100% apportionment factor reflecting IAWC's activities in Illinois rather than on a five-year average estimate of American Water's apportionment factor. Staff Ex. 10.0 at 4; AG Ex. 3.0 at 2. Mr. Effron and Ms. Hathhorn proposed to reflect the Company's State and federal accumulated deferred income taxes ("ADIT") balances at the 7.75% State income tax rate. Staff Ex. 10.0 at 4; AG Ex. 3.0 at 6-7. IAWC accepted those adjustments. IAWC Ex. 4.00SR at 4, 10. The Commission finds that these adjustments are reasonable and uncontested, and will be adopted for purposes of this proceeding.

5. Deferred Charges related to Cairo Filter Project

***5** In discovery, IAWC agreed to an adjustment to reduce rate base by $2,162,500 to correct the balance of deferred charges on Schedule B-10 for two filter projects in Cairo that should not be included as deferred maintenance. IAWC Ex. 4.00R at 4. Staff and the AG acknowledged this adjustment in testimony. AG Ex. 1.0 at 10; Staff Ex. 2.0 at 4. The Commission notes that this approach is uncontested, and it will be adopted for purposes of this proceeding.

6. Accumulated Depreciation Correction

Staff witness Hathhorn proposed adjustments to the Company's accumulated depreciation correction, "adjust[ing] rate base downward to include accumulated depreciation for two accounts" inadvertently omitted by the Company from each rate zone, as well as corrections to Rate Zone 1 for accumulated amortization and depreciation and amortization expense. Staff Ex. 2.0 at 4-5. IAWC accepted these proposed adjustments. IAWC Ex. 4.00R at 3. The Commission finds that these adjustments are reasonable and uncontested, and they will be adopted for purposes of this proceeding.

B. Contested Issues

1. Accumulated Deferred Income Taxes Balance / FIN 48

a. IAWC's Position

IAWC explains that Financial Accounting Standards Board ("FASB") Interpretation Number 48, or FIN 48, now codified as part of Accounting Standards Codification 740, is FASB's financial accounting guidance related to uncertain tax positions. IAWC explains that FIN 48 prescribes the way in which companies must analyze, quantify, and disclose the most probable outcome that will result from taking a tax position that is uncertain. IAWC Ex. 13.00R at 7.

IAWC states that some of the tax positions that are part of its method of accounting for repairs are uncertain, and it quantified FIN 48 balances accordingly. *Id.* at 8. IAWC understands that the AG argues that the Company has realized tax savings from taking the repairs deduction on its tax returns. AG Ex. 1.0 at 9. Until these deferred tax liabilities are actually paid to the relevant taxing authorities, AG witness Effron contends, they represent non-investor supplied funds that are available to the Company. Mr. Effron proposes the ADIT debit balances related to FIN 48 should be eliminated from the balance of ADIT deducted from plant in service, increasing ADIT and reducing rate base. *Id.* at 10.

IAWC states that it is willing to eliminate an adjusted FIN 48 balance from rate base, but Mr. Effron's adjustment must be revised in two ways. First, IAWC states, the ADIT balance in rate base related to FIN 48 is $3,432,525, not $18,343,822, as Mr. Effron initially proposed. The Company explains that $3,432,525 is the net FIN 48 amount after considering offsets by available net operating losses. IAWC states that this net number is what is included in ADIT. IAWC Ex. 13.00SR (Rev.) at 2.

Second, IAWC states, changes in IAWC's proposed 2015 tax filings will cause a portion of the uncertain tax positions to be realized. Therefore, IAWC explains that with respect to a 2017 test year, a portion of the deferred tax liability associated with uncertain tax positions will have been eliminated when IAWC files its 2015 tax return. IAWC Ex. 13.00R at 8-9. IAWC points out that the adjustment to prior repair deductions has been computed, and the change results in IAWC realizing $909,707 of its FIN 48 obligation, reducing the amount of the ADIT impact on rate base from $3,432,525 to $2,485,188. IAWC Ex. 13.00SR (Rev.) at 2.

***6** The Company understands that Mr. Effron also proposes that IAWC provide a method for the Commission to verify that the revised FIN 48 amounts are consistent with the filed 2015 tax return. AG Ex. 3.0 at 5. IAWC states that this is not necessary because all ADIT activity estimated by the Company through the 2017 test year has not as yet been reflected on a filed tax return. IAWC explains that that fact is inherent in using projections and basing rates on a forecasted test year. IAWC states it should not be required to document tax positions that it plans to take with respect to repairs in its 2015 tax return in a manner different than it documents any other tax projection. IAWC states it is willing to provide a confidential disclosure of IRS Form 3115 (Application for Change in Accounting Method) or a copy of IAWC's federal pro forma 2015 tax return as a compliance filing in this docket. IAWC Ex. 13.00SR (Rev.) at 3-4.

b. AG's Position

The AG states that the Commission has held and the Illinois Appellate Court has affirmed that "generally, ADIT quantifies the income taxes that are deferred when the tax law provides for deductions with respect to an item, in a year other than the year in which the item is treated as an expense for financial reporting purposes. For regulated entities, ADIT is treated as a no-cost source of capital that reduces rate base." *Commonwealth Edison Co.,* Docket No. 11-0721, Order at 56 (May 29, 2012), citing *Ameren Ill. Co. v. Ill. Commerce Comm'n,* 2012 IL APP (4th) 100962 at 5. This is because consumers pay rates that include the full tax bill but the utility does not pay some of the tax bill until a later date (the tax payments are deferred), providing the utility with consumer-supplied, no-cost capital.

In this case, the AG argues that IAWC failed to treat certain ADIT as cost-free capital, in violation of basic ratemaking and accounting principles. Specifically, while the Company took tax deductions related to repairs and realized tax savings from the repairs deduction, the Company is treating the deduction as "uncertain" under FIN 48 and not including the ADIT associated with those "uncertain" tax positions in its rate base deduction. However, until these deferred tax liabilities are actually paid to the relevant taxing authorities, the deferred tax liabilities represent non-investor, no-cost funds that are available to IAWC and should be deducted from rate base. The AG points out that the Commission came to this conclusion in IAWC's last rate case, and noted "…the FIN 48 amount represents a source of cost-free capital that should be reflected as a rate base deduction." *Ill.-Am. Water Co.,* Docket No. 11-0767, Order at 36 (Sept. 19, 2012).

The AG explains that the FIN 48 balance represents the amount of deferred tax liabilities related to uncertain tax positions that may ultimately have to be paid to the government. The FIN 48 balance represents the portion of the repairs deduction taken on IAWC's tax returns that the Company believes is uncertain upon audit by the IRS. The AG asserts that in this regard, the FIN 48 balance is no different from any other ADIT balance.

***7** AG witness Effron proposes that the ADIT deducted from plant in service not be reduced by the FIN 48 balance. In rebuttal testimony, Mr. Effron stated that the effect is to increase the balance of ADIT by $18,434,822 and to reduce the rate base by the same amount. AG Ex. 1.0, Sch. B-2; 3.0 at 5; IAWC Ex. 3.1, Sch. B-2.

In rebuttal testimony, the Company agreed that IAWC would eliminate the adjusted FIN 48 deferred tax asset balance from rate base. IAWC Ex. 13.0R at 9-10. IAWC states that it would not be claiming as much in tax repair deductions as previously claimed. IAWC proposes to update the Commission about its claimed FIN 48 and offsetting deferred tax asset in IAWC's surrebuttal testimony.

In surrebuttal testimony, the Company argued that the amount of the FIN 48 adjustment proposed by AG witness Effron in direct and rebuttal testimony (AG Ex. 1.1; AG Ex. 3.1, Sch B-2) was incorrect and provided a much smaller amount of $3,432,525. The Company claims that the amount of the FIN 48 adjustment should be further reduced to $2,485,188 to reflect the adjustment to prior repair deductions that IAWC states that it expects to take in filing its 2015 tax return. IAWC Ex. 13.00SR (Rev.) at 2-4. The AG accepts the Company's corrected amount of the FIN 48 adjustment to rate base of $3,432,525 rather than the original adjustment of $18,434,822 proposed by AG witness Effron in his direct testimony.

The AG argues that the Company, however, did not reduce rate base by the ""corrected" $2,485,188 amount in the schedules calculating the Company's proposed surrebuttal revenue requirement as the Company promised. The Company seems to have removed the FIN 48 repairs deduction for the 2015-2017 accruals in IAWC Schedules B-9 and 9.1 in IAWC Ex. 4.08SR (Rev.) at line 5, but did not remove $2,485,188 from rate base, although Company witness Wilde testified that such an adjustment would be made: "[t]he adjustment to prior repairs deductions has been computed, and the change results in IAWC realizing $909,707 of its FIN48 obligation, reducing the amount of the ADIT impact on rate base from $3,432,525 to $2,485,188" and "[t]he amount to be removed is $2,485,188." IAWC Ex. 13.00SR (Rev.) at. 2-3.

In surrebuttal testimony, as support that the rate base deduction should be $2,485,188 rather than the $3,432,525, Company witness Wilde offered to provide a confidential disclosure of Form 3115 or a copy of the IAWC federal pro forma tax return as a compliance filing in this docket. The Company's tax returns are filed 8 1/2 months after year end. IAWC Ex. 13.00SR (Rev.) at. 3-4. Thus, the AG points out the filed Form 3115 should be available during the briefing stage of this case and should be provided as evidence to support the lower rate base deduction. The AG adds that, as for the offer of a federal pro forma tax return, it is not the "actual" tax return that will be filed and should not be accepted by the Commission as proof that the Company changed its tax considerations of its repair deductions.

***8** The AG explains that in IAWC's last rate case the Commission rejected the AG's recommendation to not consider bonus depreciation in the calculation of accumulated deferred income taxes based upon the utility's testimony that American Water Works had decided to not utilize 2011 bonus depreciation. Docket No. 11-0767, Order at 70. The AG argues that it turns out that bonus depreciation was utilized in 2011 as shown in IAWC WPC — 5a. AG Group Ex. Part 2 at 10. That document shows that the Company applied bonus depreciation in 2008-2014 to its taxable income contrary to the Company's assurances in Docket No. 11-0767.

Without IAWC's filed Form 3115 evidence that the Company actually changed its tax method of accounting for repairs in filing its 2015 Corporate Income Tax return, the AG urges the Commission to reject the Company's proposed change in its tax considerations of repair deductions and reduce rate base by the AG's recommended amount of $3,432,525.

c. Commission Analysis and Conclusion

Both the Company and the AG agree that $3,432,525 is the net FIN 48 amount after considering offsets by available net operating losses. The Company further argues, however, that due to a revision to its tax method of accounting for repairs the amount of the prior repair deductions has been adjusted. The change results in IAWC realizing $909,707 of its FIN 48 obligation, reducing the amount of the ADIT impact on rate base from $3,432,525 to $2,485,188.

The AG argues that $3,432,525 should be removed from rate base, and questions the Company's amount of prior repair deductions, because the amount was removed from Schedules B-9 and 9.1 but not rate base. The AG does not appear to have a substantive objection to the Company's modification removing $2,485,188 from rate base instead of $3,432,525, but merely questions whether the Company will remove the amount from rate base. The AG requests that the Commission require the Company to file its Form 3115 to show that it actually changed its tax method of accounting for repairs in its 2015 taxes. While the Company agrees to provide Form 3115 or its federal pro forma tax return, the AG states that the pro forma tax return is not the actual form submitted to the IRS and prefers the Form 3115.

The Commission finds that the ADIT impact on rate base from the Company's FIN 48 obligation is $2,485,188. The AG proposes that the Company make a filing to show IAWC made certain repair deductions. In its Reply Briefs on Exceptions, Attachment A, the Company included its Form 3115 for the parties' review.

2. Debt Return on Pension Asset

a. IAWC's Position

The Company states it has agreed to reflect in rate base a $1,898,284 accrued liability for (non-pension) OPEB, which represents the cumulative excess of accrued OPEB costs over actual cash disbursements for OPEB. IAWC explains that this has the effect of reducing rate base. IAWC 4.00R at 15; AG Ex. 1.0 at 7.

***9** IAWC states that it also has a pension asset in the amount of $6,760,144, which reflects the difference between accrued pension expense and projected cash pension contributions. IAWC explains that when the accrual for pension expense collected from ratepayers exceeds the contribution amounts, the Commission consistently approves a reduction in rate base reflecting the difference. *See, e.g., Ill.-Am. Water Co.,* Docket No. 09-0319, Order, App. A at 2 (Apr. 13, 2010); *Ill.-Am. Water Co.,* Docket No. 07-0507, Order, App. A at 3 (July 30, 2008); *Ill.-Am. Water Co.,* Docket No. 92-0116, Order, App. A (Feb. 9, 1993). *See also Aqua Ill., Inc.*, Order, Docket No. 04-0442, Order, App. at 5 (Apr. 20, 2005); *Consumers Ill. Water Co.*, Docket No. 03-0403, Order, App. A, Sch. 3 (Apr. 13, 2004); *Cent. Ill. Light Co.*, Docket Nos. 01-0465/01-0530/01-0637 (Consol.), Order, App. A, Sch. 3 (Mar. 28, 2002); *Consumers Ill. Water Co.*, Docket Nos. 00-0337/00-0338/00-0339 (Consol.), Order, App. B-K (Jan. 31, 2001).

IAWC argues that the reverse is not true—when pension contributions exceed the pension expense amount IAWC collects through rates, as is projected to occur in this case, the Commission has not approved an increase to rate base. Docket No. 11-0767, Order at 8. It remains IAWC's position, however, that including only pension and OPEB balance sheet liabilities, but not the assets, in rate base is inconsistent. IAWC 4.00R at 15-16. IAWC therefore proposes a middle ground approach, under which IAWC receives a debt return for its pension asset. The Company explains that this is not an unprecedented proposal, because the Commission previously approved a debt return on certain pension contributions for Commonwealth Edison Company ("ComEd"). *Commonwealth Edison Co.*, Docket No. 05-0597, Order on Reh'g at 28 (Dec. 20, 2006). And, IAWC points out, the Illinois Energy Infrastructure Modernization Act ("EIMA") also allows a debt return on all pension assets. 220 ILCS 5/16-108.5(c)(4)(D). IAWC therefore considers a debt return on its pension asset a reasonable way to balance the deduction of the OPEB liability from rate base. The Company states that such a return would increase the revenue requirement by approximately $175,000. IAWC Exhibit 4.07SR.

b. Staff's Position

In surrebuttal testimony, the Company reflected an adjustment to other revenues to provide for a debt return on its pension asset. IAWC Ex. 4.02SR (Rev.), col. (p). The Company explains that, in agreeing to reduce rate base by the accrued other post-retirement benefits other than pensions liability, it also included the debt return on pension assets. IAWC Ex. 4.00SR at 9. In rebuttal testimony, the Company posits two arguments in support of its position. First, IAWC states that "the Commission permits electric utilities that choose to be regulated under the [EIMA] to include in their cost of service a debt return on pension assets" and argues the Company should be allowed the same treatment. IAWC Ex. 4.00R at 16. Staff notes, however, that the Commission permits the debt return for electric utilities because the General Assembly granted it specific authority to do so pursuant to the EIMA statute, 220 ILCS 5/16-108.5(c)(4)(D). EIMA is not applicable to utilities other than "participating" electric utilities and the Commission has not been delegated authority to permit this treatment for other utilities; thus, the Commission should reject the Company's adjustment.

***10** Second, Staff notes that IAWC suggests the prevailing argument against including a pension asset in rate base unless it was created with shareholder funds is flawed because "no item in rate base is specifically identified by its source of funding." *Id.* at 15-16. In fact, the Commission has repeatedly rejected items from rate base due to their source of funding. For example, in Docket Nos. 09-0166/09-0167 (Consol.), the Commission denied inclusion of The Peoples Gas Light and Coke Company's ("Peoples Gas") pension asset in rate base since there was no evidence in the record that it was created with shareholder funds:

> The Utilities have given us no reason to overturn our decision from their last rate case. Although the Utilities state that the pension asset was created with shareholder funds, no evidentiary support was provided. *The Commission finds no support in the record to allow for the inclusion of Peoples Gas' pension asset in rate base which in turn would allow shareholders to earn a return on ratepayer supplied funds.*

N. Shore Gas Co., Docket Nos. 09-0166/09-0167 (Consol.), Order at 36 (Jan. 21, 2010)(emphasis added).

This decision was upheld by the Appellate Court which stated in part:
The central issue before us remains whether the Commission's decision to exclude the pension asset, which it found consisted of consumer-supplied funds, from Peoples Gas' rate base was against the manifest weight of the evidence. Both the Staff's and the People's expert witness testified the pension asset constituted customer-supplied revenues and, therefore, should be deducted from the rate base calculation.

…

Based on the record before us, we find the Commission's decision with regard to the pension asset deduction is not clearly against the manifest weight of the evidence. Accordingly, we see no reason to disturb the Commission's findings.

People ex rel. Madigan v. Ill. Commerce Comm'n, 2011 IL App (1st) 100654 at ¶ 69-71.

The Commission has repeatedly denied inclusion of a pension asset in rate base when such asset was paid with ratepayer supplied funds. *See N. Shore Gas Co.*, Docket Nos. 11-0280/11-0281 (Consol.), Order at 33 (Jan. 10, 2012); *N. Shore Gas Co.*, Docket Nos. 12-0511/12-0512 (Consol.), Order at 90 (June 18, 2013); *N. Ill. Gas Co.*, Docket No. 08-0363, Order at 18 (Mar. 25, 2009); *N. Ill. Gas Co.*, Docket No. 04-0779, Order at 22-23 (Sept. 20, 2005); *N. Ill. Gas Co.*, Docket No. 95-0219, Order at 9 (Apr. 3, 1996); *MidAmerican Energy Co.*, Docket No. 14-0066, Order at 12 (Nov. 6, 2014); Docket No. 11-0767, Order at 8. Staff asserts that there is nothing in the record to establish that the Company's pension asset was funded with anything other than ratepayer funds. Further, EIMA does not authorize the Commission to allow the Company a debt return on pension assets.

***11** Staff notes that the Company mistakenly relies on the Order on Rehearing in Docket No. 05-0597, regarding a debt return on pension contributions. Docket No. 050597, Order on Reh'g at 28. The facts of that case make it unique to the issue of debt return on pension contributions. In that docket, the Commission based its conclusion on the specific details of that proceeding, and the decision was not to be construed as precedent for future proceedings concerning pension plan funding. *Id.* Exelon Corporation, the parent company of ComEd, chose to provide a contribution to the pension asset of ComEd to prefund the pension obligation. Staff continues that is not one of the facts present in this IAWC case. Moreover, in Docket No. 05-0597, the record showed the prefunding contribution to the utility pension plan resulted in a savings to ratepayers. The Commission found that the savings from this prepayment more than outweighed the cost. *Id.* IAWC has not provided sufficient evidence to meet its burden of proof that its proposal for a debt return on its pension asset is warranted or reasonable. Staff recommends that the Commission reject the Company's proposed adjustments.

c. AG's Position

AG witness Effron recommends that the Commission reduce rate base by the accrued OPEB liability in the amount of $1,898,284. AG Ex. 3.0 at 7. Mr. Effron explains that Statement of Financial Accounting Standards 106 requires the Company to accrue for the payment of future post-retirement benefits other than pensions and that when the accruals are greater than the actual cash disbursements, accrued liabilities will be reflected on the Company's balance sheets. *Id.*

The AG notes that the Commission has consistently applied this rule in IAWC's rate cases. Docket No. 11-0767, Order at App. A, page 4, line 18.

IAWC accepts Mr. Effron's adjustment, but IAWC witness Kerckhove argues that if the Company's rate base is reduced by the accrued OPEB liability, then the Company should be allowed to include in the cost of service a debt return on pension assets. In support of its previously-rejected position, the Company points to formula rates provided to participating utilities under EIMA (220 ILCS 5/16-108.5(c)(4)(D)) and ComEd's rate case in Docket No. 05-0597.

As to EIMA, the AG argues that this statute does not apply to IAWC. IAWC is not a participating electric utility under EIMA and has not satisfied the various provisions required of the participating utilities under EIMA. IAWC is not entitled to, and should not be provided, the various regulatory benefits that result from being a participating utility under that statute. In short, the AG concludes, the formula rate statute is not germane.

***12** The AG also explains that the facts of Docket No. 05-0597 do not apply to the instant case. In that case, the Commission allowed a debt return on the contribution that Exelon Corporation made to ComEd to fund the latter's pension trust fund. However, the Commission did not allow a debt return on a pension asset, which is what IAWC seeks here. The AG states that the Commission provided a debt return only on the pension contribution made by Exelon to fully fund the pension obligation. Further, the Commission based its conclusions on the specific facts of the case and cautioned that this conclusion should not be used as precedent for future proceedings. The Order stated:

> Accordingly, the Commission approves cost recovery of the Pension Asset under Alternative 3 that ComEd proposed on rehearing. However, in doing so, the Commission does not sanction the prefunding of a utility pension plan as a mechanism to increase base rates. Clearly, Exelon chose to prefund ComEd's pension plan with an equity contribution expending a rate of return. *This Commission bases its conclusion on this issue on the specific details of this proceeding, not to be construed as precedent for future proceedings concerning pension plan funding*.

Docket No. 05-0597, Order on Reh'g at 28 (emphasis added). The AG states that contrary to the facts in Docket No. 05-0597, IAWC has provided no evidence here that its pension asset was funded with anything other than ratepayer funds.

The AG argues that the Company has presented no compelling reason for the Commission to change its prior regulatory treatment of the accrued OPEB Liability and pension asset. In the Company's prior rate case, Docket No. 11-0767, the Commission denied the Company's request for a pension asset to be included in rate base while also accepting the Company's rate base deduction for the OPEB Liability. As it did in that case, the Commission should reject IAWC's position and reduce rate base by $1,898,284.

d. Commission Analysis and Conclusion

The Commission declines to make IAWC's requested adjustment. As Staff points out, this Commission has historically not allowed a return on a pension asset when expenses exceed contributions. In IAWC's past three rate cases, and in several other Article IX rate cases for other utilities, the Commission declined to do so. It is wellestablished law that the Commission is not bound by precedent and is required to look at the facts of each case to make a decision. *Mississippi Fuel Corp. et al v. Ill. Commerce Comm'n,* 1 Ill.2d 509, 513 (1953). While the Commission is not bound by precedent, when the Commission deviates from past practices it must articulate a reasoned basis to do so. *Citizens Utility Bd. v. Ill. Commerce Comm'n,* 166 Ill.2d 111, 132 (1995). Any departure by the Commission from prior orders or decisions must not be arbitrary and capricious. *United Cities Gas Co. v. Ill. Commerce Comm'n,* 235 Ill.App.3d 577, 591 (4th Dist. 1992). Moreover, "…while ordinarily an administrative action taken pursuant to statutory authority is entitled to great deference, an agency action that represents an abrupt departure from past practice is not entitled to the same degree of deference by a reviewing court." *Commonwealth Edison Co. v. Ill. Commerce Comm'n,* 180 Ill. App.3d 899, 909 (1st Dist. 1988). The Commission cannot find any new facts provided by IAWC which warrant a departure from its normal practice in this area. In fact, the 2005 ComEd Article IX rate case cited by IAWC specifically states that it is not to be construed as precedent for future cases. Docket No. 05-0597, Order on Reh'g at 28. IAWC has not demonstrated that the facts in this case are similar to Docket No. 05-0597 because its parent company has not made a contribution to fund IAWC's pension asset, nor has IAWC shown that the excess monies were generated through shareholder funds.

***13** The Commission also finds the Company's reliance on EIMA misguided. The EIMA allows specific accounting treatment on some rate base issues, such as a debt return on pension asset, provided the utility meets very specific commitments to capital investments. EIMA only applies to utilities that are deemed "participating utilities" under the definitions and law described in Sections 13-108.5 and 108.6 of the Act. Certainly, under the EIMA, water utilities cannot be participating utilities. Under no previous scenarios has this Commission applied the EIMA to any utility other than a participating utility as defined in the law. The Commission declines to do so in this case as well, and will not include $175,000 in the revenue requirement.

3. Cash Working Capital for Deferred Income Tax

a. IAWC's Position

IAWC explains that CWC is defined as the funds necessary to finance the day-to-day operations of a utility. IAWC Ex. 12.00 at 2. The necessary level of CWC is determined using a lead-lag study, which IAWC states determines the timing of cash inflows and outflows. IAWC Ex. 12.00 at 3.

The Company states that the two primary components of a lead-lag study are revenue lags and expense leads. The revenue lag represents the period of elapsed time between when a company delivers its product to its customers and when it receives payment from them. *Id.* The expense lead, IAWC states, represents the period of elapsed time between when a good or service is provided to the company and when the company pays its supplier for that good or service. *Id.* IAWC explains that the revenue lag is compared against the expense lead, and the net difference is the company's CWC requirement. *Id.*

IAWC states a dispute arose in this case regarding the CWC requirement associated with deferred income taxes. The Company explains that deferred income taxes are generally deducted from rate base, because they are considered a cost-free source of funds. IAWC Ex. 12.00 at 13; IIWC/FEA/CUB Ex. 2.0 (Rev.) at 36. In this case, the Company states it deducted deferred income tax amounts from rate base. The Company states it also assigned a zero-day expense lead to deferred income taxes in the lead-lag study to reflect the fact that there is no current expense associated with the deferred tax amounts. IAWC Ex. 12.00SR at 2.

The Company applied the same revenue lag it applies to all other revenues to the deferred tax amounts. IAWC Ex. 12.00 at 13. IAWC explains that application of the revenue lag reflects the reality that IAWC collects the dollars associated with its deferred tax liability in the same way that it collects all other revenues—by billing and collecting from its customers. IAWC Ex. 12.00SR at 2-3. The Company explains that all of its revenues are subject to a 49.3-day revenue lag, on average. IAWC Ex. 12.00R at 5.

***14** IAWC points out that Staff did not dispute IAWC's method of calculating CWC associated with deferred income taxes. Staff Ex. 10.0 at 3. However, the Company understands IIWC/FEA/CUB propose to eliminate the revenue lag applied to deferred tax amounts—in other words, apply a zero-day revenue lag. IIWC/FEA/CUB Ex. 1.0 at 1617. Although the AG offered no testimony on the subject, IAWC notes the AG supports IIWC/FEA/CUB's proposal in its briefs.

IAWC states IIWC/FEA/CUB witness Gorman makes three arguments in support of his proposal, but none of these arguments withstand scrutiny. First, IAWC notes that Mr. Gorman argued that a zero-day revenue lag was appropriate because "cash received by IAWC in rates for deferred income taxes is not currently paid." IIWC/FEA/CUB Ex. 1.0 at 16. He stated that "[e]xpenses such as deferred income tax are recorded … but do not reflect any payment to a vendor or third party." IIWC/FEA/CUB Ex. 2.0 (Rev.) at 36. The Company notes it is clear from these statements that Mr. Gorman has confused the components of the lead-lag study. IAWC states Mr. Gorman's proposal is to modify the revenue lag, yet his argument focuses on when or whether IAWC incurs an expense for deferred income taxes. IAWC explains that its lead-lag analysis already accounted for the fact that there is no current expense associated with deferred income taxes by applying a zero-day expense lead. IAWC states it also accounted for this by subtracting the deferred taxes from rate base. IAWC points out that, given Mr. Gorman's confusion on this issue, his testimony provides no support for his proposed adjustment.

Second, IAWC states that Mr. Gorman argues that a zero-day revenue lag should be applied to deferred income taxes because the taxes are "a cost-free source of cash." IIWC/FEA/CUB Ex. 1.0 at 16. But IAWC explains that the fact that deferred income taxes are a cost-free cash item has been accounted-for outside of the CWC analysis because IAWC subtracted the deferred taxes from rate base. IAWC Ex. 12.00SR at 3. For purposes of determining the appropriate revenue lag in the CWC analysis, IAWC states that the relevant inquiry is when the Company collects cash from its ratepayers. *Id.* IAWC explains that deferred tax amounts cannot become a "cost-free source of cash" to the Company until the Company actually collects the cash amounts from its customers. *Id.*

Mr. Gorman's third argument is that the deferred income taxes should be considered equivalent to depreciation and uncollectibles expenses, which are assigned a zero-day revenue lag. IIWC/FEA/CUB Ex. 1.0 at 16-17. But IAWC points out that its calculation of CWC for depreciation, uncollectibles, and deferred tax expense is consistent with past Commission findings in IAWC cases. IAWC Ex. 12.00SR at 4. The Company maintains that Mr. Gorman has presented no compelling reason to depart from Commission practice, and IIWC/FEA/CUB's proposal should be rejected.

b. Staff's Position

***15** Staff's testimony states that the Company's Schedules 10.01 ZN, CS, LC and PK present adjustments to CWC for the Company based on Staff's calculation of CWC using the Gross Lag Approach. Staff Ex. 10.0 at 3. These schedules reflect adjustments to the test year revenues and expenses for Staff's rebuttal revenue requirement. The Company agrees that the final balance of CWC will be established using the revenue requirement and methodology that is ultimately approved by the Commission in this proceeding. IAWC Ex. 12.00R at 2. Staff states that it agrees with the Company's methodology. Staff Ex. 10.0 at 3.

c. AG's Position

The AG argues that the Company mischaracterized the purpose of CWC. CWC is not measured by the receipt of cash from ratepayers in relationship to the recording of expenses. Expenses such as deferred income taxes are recorded but do not reflect payment. CWC is necessary to provide the funds required to pay the day-to-day expenses incurred by the utility to provide service to customers. Deferred income taxes are not currently paid and, therefore, do not require any funds to pay the yet-to-be paid taxes. Accordingly, the AG agrees with IIWC/FEA/CUB that there is no associated CWC requirement. IIWC/FEA/CUB Ex. 2.0 at 36-37.

IAWC witness Walker argued that Mr. Gorman's reliance on the calculation of cash working capital in electric formula rate update filings by Ameren Illinois Company ("Ameren") and ComEd as not germane because those cases "…involve electric utilities participating in the performance-based formula rate scheme established by the [EIMA]." IAWC Ex. 12.00SR at 5. The AG points out that IIWC/FEA/CUB's method for the consideration of deferred income taxes in the calculation of cash working capital has been applied in rate cases other than the electric formula rate annual update proceedings. The method was also adopted by the Commission in the last rate case proceedings of Peoples Gas and North Shore. *N. Shore Gas Co.*, Docket Nos. 14-0224/14-0225 (Consol.), 2nd Amendatory Order, App. A at 9-10 and App. B at 9-10 (Feb. 11, 2015). Consistent with its decision in the recent Peoples Gas and North Shore rate cases, the AG argues that the Commission should adopt the IIWC/FEA/CUB adjustment to subtract deferred income taxes from revenues in the CWC calculation.

d. IIWC/FEA/CUB's Position

IIWC/FEA/CUB explain that a utility's CWC consists of the funds necessary to pay the day-to-day expenses incurred by the utility to provide service for its customers. IIWC/FEA/CUB Ex. 2.0 (Rev.) at 36-37. IIWC/FEA/CUB argue that the Company overstates its CWC requirement by $1.1 million by inappropriately accounting for deferred income taxes in its CWC calculation. IIWC/FEA/CUB argue that the Commission must adjust these costs to ensure only a just and reasonable amount is included in IAWC's rates.

***16** IIWC/FEA/CUB reason that deferred income taxes are not currently paid — they are, by definition, “deferred,” which means those taxes are a non-cash item and have no associated CWC requirement. IIWC/FEA/CUB Ex. 1.0 at 16. In fact, explain IIWC/FEA/CUB, such deferred taxes are a source of cost-free funds, the benefit of which is retained by the Company until the deferred taxes are reflected as a reduction to rate base during a rate case proceeding. IAWC Ex. 12.00 at 13; IIWC/FEA/CUB Ex. 1.0 at 17. Other non-cash items like depreciation, uncollectibles expenses, and amortization expenses, which are also cost-free, non-cash capital that are subtracted from rate base, are assigned no CWC requirement. IIWC/FEA/CUB Ex. 1.0 at 16-17. IIWC/FEA/CUB state that the Company correctly recognized an expense lag of zero for deferred income taxes but did not also subtract deferred income taxes from the revenue side of the CWC calculation. IAWC Ex. 12.00 at 13. Instead, Company witness Walker assigned an average revenue lag of 49.3 days to deferred income taxes in the revenue portion of the calculation. IIWC/FEA/CUB Ex. 2.0 (Rev.) at 36. IIWC/FEA/CUB conclude that this results in inappropriately including approximately $1.1 million of CWC (a revenue requirement effect of $91,784). IIWC/FEA/CUB Ex. 1.1 at 2-4.

IIWC/FEA/CUB aver that Mr. Walker mischaracterizes the purpose of CWC by stating that Mr. Gorman's proposed adjustment ignores “the lag between IAWC's recorded deferred tax amount, and its collection of that amount from customers.” IAWC Ex. 12.00R at 5. According to IIWC/FEA/CUB, Mr. Walker's assertion ignores the fundamental principle that CWC is not measured by the receipt of cash from ratepayers in relationship to the recording of expenses. IIWC/FEA/CUB Ex. 2.0 (Rev.) at 36. Expenses such as deferred income tax are recorded (i.e. included in the books and records of the utility), but do not reflect any payment to a vendor or third party. Thus, IIWC/FEA/CUB argue that they have no place in CWC. *Id.*

In addition, IIWC/FEA/CUB argue that IAWC incorrectly asserts that Mr. Gorman's calculation of CWC is consistent with the gross lag method of calculating CWC. IIWC/FEA/CUB point out that in the pending Ameren formula rate case, Docket No. 16-0262, deferred income taxes and depreciation expenses are subtracted from revenues in the revenue portion of the CWC calculation. A similar calculation is reflected in the current annual ComEd formula rate case, Docket No. 16-0259. IIWC/FEA/CUB Ex. 2.2 at lines 6 and 7a. IIWC/FEA/CUB witness Gorman's proposed calculation is consistent with the approach used in those cases, which has been previously approved by this Commission.

e. Commission Analysis and Conclusion

The Commission agrees with the AG and IIWC/FEA/CUB. It is standard practice that deferred income taxes are treated like a non-cash item because they are not currently paid and, therefore, do not require any funds to pay the yet-to-be paid taxes. Utilities have historically excluded deferred income taxes from CWC. As stated by the Supreme Court of Illinois:

> ***17** A working capital allowance is designed to provide a return on those funds which are used to pay expenses incurred before the income produced by those expenses has been received. Such a return is not justified where payments by the utility's customers make funds available to meet current expenses without additional investment by the stockholders. Where tax accruals actually make funds available, it is error for the Commission to ignore them and fail to offset them against the working capital allowance.

City of Alton v. Ill. Commerce Comm'n, 19 Ill.2d 76, 85 (1960). While IIWC/FEA/CUB point out that deferred income taxes receive this treatment in the formula rate cases, the Commission prefers to point to other Article IX rate cases as guidance for CWC and deferred income taxes. As the AG notes, IIWC/FEA/CUB's method for the exclusion of deferred income taxes in the calculation of cash working capital was also adopted by the Commission in the last rate case proceedings of Peoples Gas and North Shore. Docket Nos. 14-0224/14-0225 (Consol.), 2nd Amendatory Order, App. A at 9-10 and App. B at 9-10. In addition to Docket No. 14-0224/14-0225 (Consol.), two other recent Article IX rate cases also properly excluded deferred taxes in the calculation of CWC. *Ameren Ill. Co.*, Docket No. 15-0142, Order, App. Sch. 8 (Dec. 9, 2015); Docket No. 14-0066, Order, App. at 9.

The Commission adopts the treatment for deferred income taxes in the CWC calculation as proposed by IIWC/FEA/CUB and supported by the AG. The Company should reduce both the expense portion and the revenue portion of the CWC calculation for deferred income taxes. This is consistent with Commission policy for the treatment of deferred income taxes and CWC.

C. Original Cost Determination

IAWC accepted Staff's recommendation that the Commission conclude and make a finding in the Final Order in this proceeding that the Company's September 30, 2015 plant balance of $1,570,415,946 be approved for purposes of an original cost determination. Staff Ex. 2.0 at 14; IAWC Ex. 4.00R at 5. The Commission finds that the original cost determination as agreed to by Staff and the Company is reasonable and uncontested. The $1,570,415,946 original cost of plant for IAWC at September 30, 2015, as presented in Staff Exhibit 2.0, is approved as the original cost of plant.

D. Recommended Rate Base

Upon giving effect to the determinations above, the Commission finds that the rate bases for the consolidated and standalone water and sewer divisions approved elsewhere in this order below are hereby approved as shown in the rate base schedules attached as Appendices to this Order.

III. OPERATING EXPENSES AND REVENUES

A. Resolved Issues

1. State Income Tax Rate

***18** IAWC proposed to revise the effective state income tax rate in developing the gross revenue conversion factor and income tax expense for IAWC in this case. The effective state income tax rate that correctly reflects IAWC's cost of state income taxes in Illinois is 7.75%, calculated using the Illinois statutory state income rate of 5.25%, plus the Illinois replacement tax rate of 2.5%, multiplied by an apportionment factor of 100%. IAWC Ex. 13.00R at 3. IAWC determined that it was incorrectly using a five-year average estimate of American Water's apportionment factor when it should have been using the 100% apportionment factor reflecting IAWC's activities in the State of Illinois, since all of IAWC's sales are sourced to Illinois. *Id.* Using a 100% apportionment for IAWC properly represents IAWC activities and the amount it will ultimately pay as its share of the American Water combined group. *Id.* Staff witness Hathhorn and AG witness Effron both accepted IAWC's proposal to use the 7.75% state income tax rate, based on a 100% apportionment factor. Staff Ex. 10.0 at 4; AG Ex. 3.0 at 2. The Commission finds that the state income tax rate, as agreed to by the Company and Staff, is accurate and will be adopted for purposes of this proceeding.

2. Income Tax Expense

In rebuttal, AG witness Effron stated that while the Company appears to agree with his corrections to the calculation of income tax expenses, the Company still had not made those corrections. AG Ex. 3.0 at 15. In surrebuttal, IAWC witness Kerckhove explained that the current income tax was calculated correctly in the Company's rebuttal testimony. The adjustment to income tax expense used in the Company's rebuttal filing was an error, however, since it used the Company's initial rate case filing as the starting point for the adjustment. The current income taxes in the Company's surrebuttal exhibits match the calculation of income tax expense on Company Pro Forma Present. IAWC Ex. 4.00SR at 11. The Commission finds that the income tax expense, as agreed to by the AG and the Company, is accurate and will be adopted for purposes of this proceeding.

3. Advertising Expense

Schedule C-8 presents IAWC's expenses for advertising that informs consumers how they can conserve water or reduce peak demand, advertising required by law, and advertising regarding service interruptions, safety measures, and emergency conditions. IAWC Ex. 4.00 at 19. Staff witness Kahle proposed an adjustment to reduce the Company's proposed advertising expense level by items he deemed of a promotional, goodwill or institutional nature. Staff Ex. 3.0 at 7, Sch. 3.03 at 1. IAWC accepted that adjustment. IAWC Ex. 4.00R at 4. The Commission finds that IAWC's advertising expense, as adjusted by Staff and agreed to by the Company, is reasonable and will be adopted for purposes of this proceeding.

4. Lobbying Expense

***19** Schedule C-2.5 presents lobbying expenses that IAWC removed from the test year revenue requirement. IAWC Ex. 4.00 at 14. Staff witness Kahle proposed an additional adjustment for employee expenses related to lobbying that IAWC inadvertently included in test-year operating expenses. Staff Ex. 3.0 at 9, Sch. 3.05. IAWC accepted that adjustment. IAWC Ex. 4.00R at 4. The Commission finds that IAWC's lobbying expense, as adjusted by Staff and agreed to by the Company, is reasonable and will be adopted for purposes of this proceeding.

5. Outside Professional Services Expense

Schedule C-6.2 presents expenses for Outside Professional Services 2014 through 2017. IAWC Ex. 4.00 at 18. Staff witness Kahle and AG witness Effron each proposed an adjustment to remove certain outside professional expenses that IAWC inadvertently included in test year operating expenses. Staff Ex. 3.0 at 10, Sch. 3.06; AG Ex. 1.0 at 25. IAWC accepted that adjustment. IAWC Ex. 4.00R at 4. The Commission finds that IAWC's outside professional services expense, as adjusted, is reasonable and will be adopted for purposes of this proceeding.

6. Invested Capital Tax

Schedule C-2.10 presents an adjustment to the test year forecast for invested capital tax that aligned with IAWC's initially-proposed capital structure balances. IAWC Ex. 4.00 at 15. Staff witness Kahle recommended that the final amount of invested capital tax be based on the average combined long-term debt and common equity from the capital structure adopted by the Commission. Staff Ex. 3.0 at 9. AG witness Effron agreed. AG Ex. 3.0 at 17. In light of the parties' agreement regarding the capital structure balances, IAWC accepted the adjustments to invested capital tax. IAWC Ex. 4.00R at 13; IAWC Ex. 4.00SR at 10. The Commission finds that IAWC's invested capital tax expense, as adjusted, is reasonable and will be adopted the purposes of this proceeding.

7. Unaccounted-For Water Expenses

Staff witness Kahle recommended an adjustment to reduce chemical and power expenses associated with the unaccounted-for water over the maximum allowance in IAWC's tariffs. Staff Ex. 3.0, Sch. 3.02; Staff Ex. 7.0 at 6. IAWC already removed, however, the excess production costs above the tariff limitations, as shown in workpapers WPC-2.2c and WPC-2.2d. IAWC Ex. 4.00R at 11. Further, Staff's calculations overstated the appropriate adjustment—already included in IAWC's calculations—because they did not reflect the full amount of water not used for billed sales but used for known purposes, and because they included a weighted factor for the lower unaccounted-for water tariff limits in the Chicago Metro district's purchased water areas. *Id.* at 12. Staff witness Sperry did not object to IAWC's calculations and recommended that the Commission accept IAWC's adjustment for unaccounted-for water. Staff Ex. 15.0 at 5. The Commission finds that IAWC's unaccounted-for water expense, as agreed to by the parties, is reasonable and will be adopted for purposes of this proceeding.

8. Depreciation/Amortization Adjustment

***20** IAWC included a depreciation adjustment in its revenue requirement, as shown on IAWC Schedules C-12 and C-2.11. IAWC Ex. 4.00R at 18. AG witness Effron proposed an adjustment to the depreciation expense shown on Schedule C-2, "in the calculation of adjusted operating income under present rates, to comport with the depreciation expense shown on Schedules C-2.11 and C-12." AG Ex. 1.0 at 22. Mr. Effron's proposal, however, adjusted amortization expense recorded in Accounts 406 and 407. This was also included in IAWC's last three rate cases. IAWC Ex. 4.00R at 18. Mr. Effron agreed and withdrew his proposal. AG Ex. 3.0 at 14. The Commission finds that IAWC's unadjusted depreciation expense is reasonable and uncontested; it will be adopted for purposes of this proceeding.

9. Miscellaneous/Other Revenues

IIWC/FEA/CUB witness Gorman proposed an adjustment to IAWC's test year Miscellaneous/Other Revenues to more closely align with 2014 and 2015 Miscellaneous/Other Revenues levels. IIWC/FEA/CUB Ex. 1.0 at 8-9. AG witness Effron also proposed an adjustment to these revenues to reflect actual revenues through September 2015 and proposed revenues for October through December 2015. AG Ex. 1.0 at 11-12. IAWC accepted Mr. Gorman's proposal in part, and proposed that the adjusted level of Miscellaneous/Other Revenues through the 12 months ending May 2016 be used for the 2017 test year. IAWC Ex. 4.00R at 17, 19-20. Mr. Effron accepted this adjustment. AG Ex. 3.0 at 7. Mr. Gorman also accepted the adjustment and recommended an increase in Miscellaneous/Other Revenues for the Chicago-Metro Sewer district, since IAWC's proposed time period did not reflect normal operations in this district. IIWC/FEA/CUB Ex. 2.0 (Rev.) at 22-23. IAWC accepted Mr. Gorman's adjustment. IAWC Ex. 4.00SR at 7-8. The Commission notes that the parties are in agreement regarding this issue. The Commission finds that IAWC's miscellaneous/other revenues, as adjusted, are reasonable and will be adopted for purposes of this proceeding.

10. Current Rate Case Expense

IAWC requested rate recovery of $2,829,388 in rate cases expenses, amortized over two years. IAWC Ex. 4.00 at 19-21. Of that total, $2,682,915 is the projected cost for outside and affiliate expertise to prepare and litigate this rate case. *Id.*

at 19. The remaining $146,476 is the unamortized balance of Docket No. 11-0767 rate case expense, approved by the Commission as just and reasonable in that rate case.

Section 9-229 of the Act requires the Commission to assess the justness and reasonableness of IAWC's rate case expenses. 220 ILCS 5/9-229. In 2015, the Commission adopted the Part 288 rules, which guide this assessment. 83 Ill. Admin. Code, Part 288; *Ill. Commerce Comm'n on Its Own Mot.*, Docket No. 11-0711, Order at 1 (June 3, 2015). The Commission finds that, consistent with that authority, IAWC supplied for the Commission's review documentation supporting the justness and reasonableness of its current rate case expenses, as explained below. The Commission further finds that IAWC has otherwise complied with the requirements of Part 288, as also explained below.

***21** IAWC states that its $2,682,915 current rate case expense projection is composed of expenses for the following rate case work, performed by the following professionals, as shown on the Company's Schedule C-10:

• Cash Working Capital Study and support — Harold Walker III, Gannett Fleming;

• Cost of Service Study and support — Paul R. Herbert, Gannett Fleming;

• Demand Study and support — Paul R. Herbert, Gannett Fleming;

• Forecast Audit — Rick Gratza, Kerber, Eck & Braeckel, LLP;

• Rate of Return study and support — Paul R. Moul, Paul Moul & Associates;

• Legal support — Whitt Sturtevant LLP;

• Revenue Requirement support [1] — American Water Works Service Company; and

• Compensation Study and support — Robert V. Mustich, Willis Towers Watson. [2]

In direct testimony, IAWC explained what the anticipated rate case work entailed, why it was prudent to anticipate such rate case work, and why IAWC chose the professionals it did to perform the rate case work, including their qualifications and the reasonableness of their fees. IAWC Ex. 4.00 at 29-45.

IAWC further explained that it engaged the same or similar professionals to prepare and litigate Docket No. 11-0767. The total amount of rate case expense approved in that case for those professional services was $2,332,541; the total amount actually incurred was $2,414,670. IAWC Ex. 4.00 at 20. IAWC explained that its current $2,682,915 rate case expense projection is slightly higher due to moderate increases in consultant costs, including the costs for necessary rate case studies, and the costs to comply with new legal requirements, such as the enhanced customer notice required by recent amendments to the Act. *Id.* at 20-21, 30; 220 ILCS 5/9-201(a).

***22** IAWC otherwise complied with Part 288 of the Commission's rules. Part 288 governs outside and affiliate rate case expenses for which recovery is sought by the utility through rates. 83 Ill. Admin. Code 288.10. IAWC also supplied the information required by that rule, related to its current rate case expenses. *See* 83 Ill. Admin. Code 288.40(a).

As required by Part 288, IAWC provided in discovery (and in its direct case) this information to assist Staff and other parties in developing a recommended amount of rate case expense:

• requests for production, engagement agreements, and direct testimony describing the terms of engagement between IAWC and outside counsel and technical experts, including their support staff, which describe the nature of the services to be provided, by whom, the attendant hourly rates, and whether specific overhead expenses are excluded from those rates, 83 Ill. Admin. Code 288.30(a)(1), (d); IAWC Ex. 4.00 at 32-45; IAWC Ex. 4.00R at 9; IAWC Ex. 4.00SR at 13; IAWC Ex. 15.01SR at 3-43, 112-13;

• for outside counsel services, which were provided under hourly rate contracts, invoices that clearly indicate the services provided, who provided them, the time spent providing them, and the applicable hourly rates, 83 Ill. Admin. Code 288.30(a)(2); IAWC Ex. 15.01SR at 91-107, 297-312, 349-64, 380-406, 409-38;

• for outside technical expert services, which were provided under hourly rate contracts, some of which included a not-to-exceed component, invoices that clearly indicate the services provided, who provided them, the time spent providing them, and the applicable hourly rates. 83 Ill. Admin. Code 288.30(a)(3); IAWC Ex. 15.01SR at 44-80, 108-10, 114-296, 315-48, 367-79, 407-08, 439-47; and

• for the Service Company services, documentation that describes the services provided, the employee number and title of the persons providing those services, the time spent providing the services on a daily basis, the hourly rates, without gross-up for benefits, like performance pay, and the resultant total amounts charged. 83 Ill. Admin. Code 288.30(a)(6); IAWC Ex. 15.02SR; IAWC Ex. 15.03SR at 8, 30, 60; IAWC Ex. 4.10SR.

IAWC also provided with its direct case:
• the information required by Part 285.3085 (Schedules C-10 and C-10.1). 83 Ill. Admin. Code 288.30(b)(1); IAWC Ex. 4.00 at 19-21;

• explanations of the processes, procedures, and controls IAWC uses to ensure that (a) work performed by outside professionals does not duplicate the work of IAWC personnel, and (b) bills from outside professionals are accurate, reasonable, and not redundant, before payment is made. 83 Ill. Admin. Code 288.30(b)(3)-(4); IAWC Ex. 4.00 at 34, 37-38, 40-43;

***23** • explanations of the reasonableness of the fees to be paid to outside professionals, considering factors enumerated in 83 Illinois Administrative Code 288.40, such as the nature and extent of the work required, the skill required to perform that work, and the professionals' credentials. 83 Ill. Admin. Code 288.30(b)(5), 288.40; IAWC Ex. 4.00 at 29-45; and

• the rationale for IAWC's proposed two-year amortization period—the Company's historical rate case frequency and the effect on rate case timing of the Commission's Order in Docket No. 15-0017, the rulemaking to amend 83 Illinois Administrative Code, Part 656, "Qualifying Infrastructure Plant Surcharge." 83 Ill. Admin. Code 288.30(b)(6); IAWC Ex. 4.00 at 19-20.

IAWC also provided with its direct, rebuttal, and surrebuttal cases summary schedules of its rate case expenses, which showed the total projected, total incurred, and total remaining rate case expenses for each professional. 83 Ill. Admin. Code 288.30(c)(1)- (4); IAWC Ex. 4.03 (Rev.); IAWC Ex. 4.12R; IAWC Ex. 4.10SR; IAWC Ex. 15.02SR; IAWC Ex. 15.03SR. IAWC Exhibit 4.10SR also indicates where in IAWC's discovery responses the invoices supporting each expense incurred to date can be found. IAWC Ex. 4.10SR. *See also* IAWC Ex. 15.01SR; IAWC Ex. 15.02SR; IAWC Ex. 15.03SR (collecting those responses).

IAWC also filed the Affidavit of Rich Kerckhove, attesting that the compensation paid or to be paid by IAWC to outside and affiliate professionals for their rate case work is supported by billings or other documentation that are true and accurate; support costs that were reasonable to prepare and litigate the rate case; were reviewed and approved by IAWC management prior to payment; and are not duplicative. IAWC Ex. 14.00SR. Mr. Kerckhove also attested that IAWC has paid, or will pay, the billed amounts for which IAWC requests rate recovery as rate case expense. 83 Ill. Admin. Code 288.30(e)(1)-(3); IAWC Ex. 14.00SR; IAWC Ex. 4.00SR at 15.

Finally, as explained and as required by Part 288, IAWC submitted all of its rate case expense support—including testimony, summary schedules, outside professional requests for proposals, engagement agreements, invoices, and discovery responses— for the evidentiary record to aid the Commission's assessment of the expense. 83 Ill. Admin. Code 288.30(f); IAWC Ex. 4.00SR at 12-13; IAWC Ex. 4.11SR; IAWC Ex. 15.01SR; IAWC Ex. 15.02SR; IAWC Ex. 15.03SR. Additionally, the Commission finds that the work product of the professionals that performed the rate case work, including IAWC's testimony, exhibits, and legal filings on the Commission's e-Docket system, further support the justness and reasonableness of IAWC's rate case professionals' expenses.

***24** In light of the ample record evidence that IAWC has supplied supporting the justness and reasonable of its rate cases expenses and described above, the Company's compliance with Part 288, the recommendation of Staff regarding IAWC's rate case expenses, and the agreement of the parties, the Commission approves IAWC's requested $2,829,388 level of rate case expense. Specifically, the Commission finds that the compensation for attorneys and technical experts to prepare and litigate this proceeding that are included in the total approved rate case expense amount of $2,829,388 are just and reasonable pursuant to Section 9-229 of the Act. 220 ILCS 5/9-229.

11. Unamortized Docket No. 09-0319 Rate Case Expense

IAWC originally requested recovery of unamortized, unrecovered Docket No. 09-0319 rate case expense inadvertently omitted from Docket No. 11-0767. IAWC Ex. 4.00 at 20. Staff witness Kahle and AG witness Effron opposed recovery of the expense, and proposed an adjustment to remove it from the revenue requirement. Staff Ex. 3.0 at 4; AG Ex. 1.0 at 20. To narrow the issues in this case, IAWC accepted that adjustment. IAWC Ex. 4.00SR at 7. In light of the parties' agreement, the Commission finds that Staff and the AG's adjustment is reasonable, and it is approved for the purposes of this proceeding.

12. Long-Term Performance Plan Expense

IAWC awards long-term performance pay to attract and retain the critically-skilled employees needed to run its business and to focus those employees on the long-term financial success of the Company. IAWC Ex. 9.00 at 10; IAWC Ex. 9.01 (Rev.) at 8-9; IAWC Ex. 7.00R (Rev.) at 26. *See also* Staff Ex. 3.0, Attach. G at 17-38. IAWC states that its customers benefit when their utility is financially healthy, because this mitigates the costs that customers ultimately pay through rates. *See* IAWC Ex. 7.00R (Rev.) at 2136. For example, IAWC explains, financial success demands attention to operating efficiency; unless the utility controls or reduces its costs, it cannot achieve earnings per share or other financial goals. *Id.* at 24. And, IAWC maintains, a financially healthy utility can secure the debt capital that it needs to operate at reasonable costs—costs that customers pay in rates. IAWC Ex. 7.00R (Rev.) at 26; IAWC Ex. 2.00 at 23.

For these reasons—and because its employees' total compensation, which may include long-term performance pay, is prudent and reasonable—IAWC initially requested recovery of its test year Long-Term Performance Plan expense. However, to narrow the issues in this case and without waiving its right to seek recovery of long-term performance pay costs in future proceedings, IAWC withdrew its request, and accepted Staff's proposed adjustment to its Long-Term Performance Plan expense, as corrected by Staff in discovery. IAWC Ex. 7.00SR (Rev.) at 10-11; IAWC Ex. 4.00SR at 6-7; IAWC-Staff Stip. Cross Ex. 1.00 at 17, 19.

***25** In light of the parties' agreement, the Commission finds that Staff's adjustment, as agreed to by IAWC, is reasonable and it is approved for the purposes of this proceeding.

B. Contested Issues

1. Payroll Expense

a. IAWC's Position

Payroll expense, the Company explains, is an ordinary and necessary cost of doing business that must be recovered in rates. *Madigan*, 2011 IL App (1st) 100654 at ¶ 49, *citing Bus. & Prof'l People for Pub. Interest v. Ill. Commerce Comm'n,* 146 Ill. 2d 175, 247 (1991); *Villages of Milford v. Ill. Commerce Comm'n,* 20 Ill. 2d 556, 565 (1960). IAWC explains that productivity enhancements have allowed it to reduce its employee headcount since its 2011 rate case, saving $300,000 in test year payroll expense here. IAWC states that the reduction is the result of IAWC's organizational streamlining efforts and technology initiatives, like the Company's Advanced Meter Reading program, which has allowed IAWC to eliminate 16 full-time equivalent positions, and Business Transformation, American Water's system-wide deployment of new, integrated information technology systems to improve technological efficiencies, increase automation and promote more effective business processes. IAWC Ex. 2.00 at 10, 16, 19. IAWC states that these initiatives allow IAWC to complete more work with fewer people than in 2011, but at lower labor and related costs to IAWC's customers. *Id.* at 19. IAWC maintains that any further reductions to employee headcount and payroll expense should be rejected.

IAWC explains that its test year payroll expense reflects the staffing level that IAWC projects it will need to meet its water and sewer service obligations to Illinois customers in 2017—an average of approximately 470 full-time positions. IAWC explains that total equals 482 average full-time positions (479 full-time permanent positions each month of the test year, and 13 full-time temporary summer positions, June through August), reduced by 2.5% (approximately 12 positions), to account for anticipated position vacancies in the test year. IAWC Ex. 2.00 at 18-19; IAWC Ex. 2.00R (2d Rev.) at 2, 3. IAWC points out that its May 2016 headcount of 442 plus the 24 positions the Company is actively recruiting or planning to hire in 2016—466 total positions— already approximates its test year 470-headcount projection. IAWC states that each position is essential to the core functions of IAWC's operations: construction, operation, and maintenance of IAWC's water distribution and wastewater collection systems, meter testing and repair, customer service, and management of the personnel who perform that critical work. *Id.* at 3; IAWC Ex. 2.01R.

When IAWC staffs its water and sewer operations, it reviews each vacant position for overall need and considers, among other things, whether the position should be transferred, modified, or even eliminated. IAWC explains that it similarly evaluates new positions that it may need to meet changing regulatory requirements, optimize new technology, and most effectively serve customers. IAWC Ex. 2.00 at 19. IAWC maintains that this continuous focus on appropriate staffing needs allows the Company to effectively control labor costs, while maintaining the workforce necessary to meet its service obligations to Illinois customers. IAWC Ex. 2.00R (2d Rev.) at 3-4.

***26** IAWC states that all of the positions that it is actively recruiting for, or plans to recruit for, in 2016 are critical to serving IAWC's customers. IAWC Ex. 2.00R (2d Rev.) at 3. Therefore, IAWC's President and Vice President of Operations have approved those positions. *Id.* at 4. IAWC maintains that before the end of 2016 and into the 2017 test year, the Company may recruit for additional, but currently unplanned, full-time positions as business circumstances dictate, to meet IAWC's service obligations. *Id.* at 3.

IAWC further explains that test year payroll expense accounts for 2.5%, or 12 anticipated position vacancies. This is because, while IAWC continuously strives to fill all open positions, historically, the Company has been unable to fill all of its staffing needs. First, IAWC notes that the utility workforce is aging and retiring, and IAWC has lost employees due to attrition. *Id.* at 5. Second, IAWC explains that it is difficult to attract new, STEM-qualified (Science, Technology, Engineering, Mathematics) talent to the public utility industry to fill vacancies left by retiring talent. *Id.* Finally, IAWC explains, the Company has recently increased its focus on diversifying its workforce, with great success: in 2014 and 2015, the majority of IAWC's new hires identified with a minority population. But this focus, IAWC explains, means that there may be delays in filling open positions. *Id.*

IAWC emphasizes that no party disputes that IAWC's approach to staffing its operations is reasonable. Further, no party disputes IAWC's current headcount, the need for the 24 full-time positions that IAWC is recruiting for and plans to fill in 2016, or the need for the attendant work. Moreover, IAWC points out, no party disputed that IAWC may need to recruit more positions beyond its current recruitment plans, in 2016 and 2017, to meet its service obligations to Illinois customers. IAWC Ex. 2.00SR at 6.

Despite this, IAWC explains, Staff witness Kahle, AG witness Effron, and IIWC/FEA/CUB witness Gorman proposed to further reduce IAWC's test year headcount and payroll expense, based on nothing more than IAWC's historical position vacancies since 2014, albeit each to varying degrees. *Id.* at 2. Mr. Kahle would reduce the expense by 5.40%; Mr. Effron, by 5.77%; and Mr. Gorman, by 7.59%. Staff Ex. 11.0REV at 11; IAWC Ex. 2.00SR at 7; IIWC/FEA/CUB Ex. 2.0 (Rev.) at 26.

In response, IAWC explains it is already operating with a lean staff, so its historical vacancy experience is not representative of its future staffing needs. IAWC explains that the reduction is one benefit of Business Transformation, which was established in 2013. The Company explains that Business Transformation changed the way IAWC employees work; they perform the same functions, just differently and more efficiently. IAWC explains that the advent of Business Transformation in 2013 meant a period of "right-sizing" for IAWC's workforce—in 2014 and 2015. Thus, IAWC explains, its vacancy experience those years is not a good predictor of its future staffing needs. IAWC Ex. 2.00R (2d Rev.) at 6. IAWC points out that Staff, the AG, and IIWC/FEA/CUB all wholly ignored this key context for IAWC's 2014 and 2015 staffing levels.

***27** IAWC also emphasizes that, at a minimum, any payroll expense adjustment requires an offsetting adjustment for increased overtime expense—something the AG and IIWC/FEA/CUB ignore or dismiss. IAWC explains that when it cannot fill a budgeted position, current employees must perform the work—at time-and-a-half pay—in addition to their other responsibilities, so IAWC can meet its service obligations to Illinois customers. IAWC Ex. 2.00R (2d Rev.) at 7; IAWC Ex. 2.00SR at 2, 3-4. Therefore, IAWC explains, where historical headcount vacancies have exceeded budget, IAWC's historical overtime expenses likewise have exceeded budget—by $742,000 in 2013; by $808,000 in 2014; and by $459,000 in 2015. IAWC Ex. 2.00R (2d Rev.) at 7. As of May 2016, IAWC states, its 2016 overtime expense was 69% over budget. IAWC Ex. 2.00SR at 4. In other words, on average, 2013 to date, IAWC's overtime expenses have exceeded budget by 43%, offsetting budgeted payroll expense reductions those years.

IAWC points out that IIWC/FEA/CUB ignore this. The AG, however, recognizes that overtime expenses can be attributable to the need to compensate for headcount vacancies. But rather than recognizing any offset to its payroll expense adjustment for this, IAWC explains, the AG argued that "[o]vertime can be the result of many factors." IAWC notes that the AG then cited only one: American Water's stated need in 2014 for increased overtime labor to remedy main breaks resulting from harsh winter weather. Yet this does not aid the AG's position, IAWC explains. If IAWC had the workforce sufficient to respond to unanticipated circumstances, like an increased number of main breaks, its overtime expenses would be less. IAWC Ex. 2.00SR at 6. IAWC affirms that the AG's example simply highlights IAWC's need for flexibility to add headcount beyond its June 2016 recruitments, to ensure the workforce necessary to respond to unanticipated circumstances. *Id.*

IAWC explains that some overtime is expected and appropriate, and therefore IAWC includes overtime expense in its annual budget. IAWC Ex. 2.00SR at 5. IAWC explains that excessive overtime, however, is not desirable. Overtime hours are taxing on employees. IAWC explains that these hours affect employee satisfaction and risk the Company's ability to maintain the stable workforce it needs to serve Illinois customers. *Id.* And excessive overtime hours are not sustainable, IAWC continues. Although IAWC remains focused on safety, it notes that excessive overtime can foster safety concerns. Most IAWC employees who put in overtime hours are field personnel, and an 8-hour shift becomes a 12-hour shift. Simply put, IAWC states, it is better for IAWC to fill planned full-time positions than for IAWC's current workforce to continue to do the work of those positions by working overtime hours. *Id.*

***28** IAWC notes that Staff recognized that forecasting payroll expense is more dynamic than the AG and IIWC/FEA/CUB presume, because Staff's adjustment accounted for the overtime labor that must compensate for unfilled headcount positions. IAWC explains that its projected test year overtime expense is $1,311,710. IAWC Ex. 2.00SR at 4. IAWC explains that applying the Company's historical average overtime expense variance of 43% to the test year expense level produces an increase in overtime expense of $559,444. *Id.* IAWC explains that Staff witness Kahle agreed that that increase appropriately offsets his $702,756 payroll expense adjustment, and he reduced the amount of his adjustment to $143,312. IAWC-Staff Stip. Cross Ex. 1.0 at 18, 20.

IAWC remains concerned, however, that Staff's adjustment, while more reasonable than the AG's and IIWC/FEA/CUB's because it appropriately recognizes overtime expense, is overstated. IAWC notes that Staff argued that IAWC's staffing plans as of June 2016 produce a vacancy rate of 4.36%. Staff didn't dispute the need for any of the planned positions. Yet, IAWC notes, Staff proposed a higher test year vacancy rate - 5.4% - which would remove some of those undisputed planned positions. IAWC explains therefore that, by Staff's own calculation, Staff's proposed vacancy rate is overstated.

IAWC concludes that it has already significantly reduced its workforce, which has mitigated the payroll expense that customers pay through rates. IAWC maintains that the Commission should support such efforts, not constrain payroll expense—and, consequently, IAWC's ability to fill necessary positions with talented, diverse personnel— further. IAWC urges the Commission to reject any adjustment to IAWC's forecasted 2017 test year payroll expense. That expense reasonably reflects the future staffing that IAWC needs to meet its service obligations to Illinois customers. IAWC states that if, however, the Commission adjusts IAWC's forecasted payroll expense for historical vacancies, the Commission must also recognize the consequent increase in overtime expense, which offsets those vacancies.

b. Staff's Position

Staff states that the Commission should adopt its proposed adjustment to reduce test year payroll expense in order to reflect the Company's history of unfilled budgeted positions. During 2014, 2015 and the first two months of 2016, the Company left unfilled 5.4% of their budgeted positions, on average, but allowed only for a vacancy rate of 2.5% in the test year. Staff's adjustment increases the test year vacancy rate to the Company's historical actual average vacancy rate of 5.4%. Staff Ex. 3.0 at 14-15. In rebuttal, Staff modified its position to divide its proposed adjustment between expensed and capitalized payroll rather than reflect the entire adjustment as an operating expense. Staff Ex. 11.0 at 10-11. Staff further reduced its proposed adjustment to reflect the offsetting effect of additional overtime expense associated with unfilled positions. The overtime expense estimate was supplied by the Company. IAWC-Staff Stip. Cross Ex. 1.00 at 18 and 20. Staff's modified adjustment continues to reflect a vacancy rate of 5.4%.

***29** The Company argues that its vacancy rate for the test year should not be reduced because the Company plans to fill several vacant positions. IAWC Ex. 2.00R at 2-5. The Company, however, did not present a plan that supports this argument. The Company proposes a 4.36% vacancy rate. Staff Ex. 11.0 at 11-12.

Staff notes in briefs that the Company alleges three reasons why it has been unable to fill its full-time positions, but Staff points out that none of these reasons support the Company's claim that its ability to fill positions will be better in the test year than demonstrated by its recent history. The Company gives no explanation of how it will improve on its history of filling vacant positions as the available workforce is reduced. The Company does not explain why the Commission should accept as a given that there are not enough available graduates with STEM-related degrees. Finally, Staff states that the Company does not explain why hiring minorities may result in delays in filling open positions.

According to Staff, the Company's proposed vacancy rate is out of line with its historic vacancy rates and is not supported by the Company's plan. Staff maintains that its adjustments to the vacancy rate to reflect the Company's average historical rate over the past three years of 5.4% should be adopted.

c. AG's Position

The AG notes that IAWC's actual vacancy percentage since 2014 has been consistently higher than the vacancy percentage assumed by the Company in forecasting the test year headcount. For May 2016, the most recent month in which data was available, the actual vacancy rate was 10.34%; for the months between July 2015 and April 2016 the highest and lowest monthly vacancy rates ranged from 7.10% to 9.41%, and the average actual monthly vacancy rate for 2014 was 4.79%. AG Ex. 3.1, Sch. C-2.

Company witness Smyth asserted in rebuttal that if positions are unfilled, current IAWC employees and/or temporary employees must do the required work, increasing IAWC's overtime and temporary labor expenses. He also claimed that IAWC's increased overtime and temporary labor expenses since 2013 are due to IAWC's unfilled planned full-time positions. IAWC Ex. 2.00R at 2-10. The AG argues that Mr. Smyth's contention regarding temporary labor expense is contradicted by the fact that its actual temporary labor expense from January through May, 2016 of $23,000 is below the budgeted year-to-date amount of $35,000. AG Group Ex. Part 3 at 8-9.

Moreover, the AG asserts that the Company's argument that its overtime expense would increase with a higher vacancy rate is unfounded. There can be many reasons for increased overtime and temporary labor expenses. Overtime can be the result of many factors, and only a percentage of IAWC's overtime can be attributable to its actual vacancy rate. AG Group Ex. Part 3 at 38-39. The AG cites page 45 of the Form 10-K for December 31, 2014 for American Water Works which states that there was "…an increase in salaries and wages expense in 2014 as a result of annual wage increases and *increased overtime expense attributable to an increased number of main breaks as a result of the harsh winter weather conditions* and increases in severance expense as a result of the restructuring of certain functions…." AG Ex. 3.0 at 9 (emphasis added). The AG claims that the Company has not provided any evidence of the percentage of the increased overtime costs that is attributable to the increased vacancy rate, so the Commission should not consider the incremental overtime costs in its determination of an adjustment to recognize the Company's increasing vacancy rate.

***30** The AG adds that IAWC has not provided any data that would permit the Commission to calculate a percentage of the increased overtime costs that might be attributable to the increased vacancy rate. Clearly, the percentage of the increased overtime costs attributable to the increasing vacancy rate is not 100%. Unless the Commission chooses to arbitrarily select a percentage of overtime that might be attributable to the Company's increasing vacancy rate, the Commission should not consider the incremental overtime costs in its determination of an adjustment. Applying the vacancy rate proposed by AG witness Effron rather than the higher vacancy rate proposed by IIWC/FEA/CUB witness Gorman would provide a fair compromise.

The AG argues that in addition to adopting the adjustment to recognize the Company's increasing vacancy rate it should also adopt the derivative adjustments proposed by AG witness Effron: (1) FICA payroll tax also proposed by Staff witness Kahle and IIWC/FEA/CUB witness Gorman; (2) 401K expense and group insurance adjustments also proposed by Mr. Gorman; (3) defined contribution plan that provides all employees hired after 1/1/2006 a 5.25% base pay defined contribution plan (AG Group Ex. Part 3 at 12); (4) capitalized 2017 payroll as proposed by Staff witness Kahle; and (5) capitalized 2016 payroll as the capitalized 2016 payroll represents a forecast and is not the actual capitalized 2016 payroll.

The AG says that in response to IAWC's claim that Mr. Effron had improperly applied certain benefits to the vacancy positions, including the employee benefits of pension, OPEB, retiree medical, and the Employee Stock Purchase Plan, Mr. Effron removed those items from his calculation of his proposed adjustment in his rebuttal testimony.

d. IIWC/FEA/CUB's Position

IAWC seeks recovery of a level of payroll expense based on a budgeted/authorized employee level of 482. IIWC/FEA/CUB Ex. 1.0 at 9. IIWC/FEA/CUB argue that IAWC's recent budgeted levels of employees have proven to be very inaccurate when compared to actual levels. *Id.* at 9-10. IIWC/FEA/CUB point out that on a rolling 12-month basis, since December 2014, IAWC's budgeted number of average employees has been 20 to 38 employees (or 4% to 8%) higher than its actual employee levels. IIWC/FEA/CUB Ex. 2.0 (Rev.) at 25 Table 1. Using the most recent available data, updated through May 2016, the disparity between budgeted and actual employee levels has increased each month for a full year. IIWC/FEA/CUB Ex. 2.0 (Rev.) at 24-25.

IIWC/FEA/CUB reason that, given the Company's recent history of overestimating its employee levels, its 2017 estimate is likely inflated. Mr. Gorman made adjustments to IAWC's employee level to reflect more accurate recent historic levels. To calculate his adjustment, Mr. Gorman used the last known average level of employees for calculating salaries and wages, payroll taxes, and benefits. IIWC/FEA/CUB Ex. 1.0 at 10.

According to IIWC/FEA/CUB, the Company's claims that its estimated employee levels will be realized are undermined by its recent historical experience, its attrition rates versus new hire rates, and the length of some vacancies (as long as 297 days). IIWC/FEA/CUB Ex. 2.0 (Rev.) at 27. While IAWC witness Smyth attempted to show that the Company is in the process of filling its vacant positions, only two of the 24 employees listed in IAWC Ex. 2.01R accepted offers as of the filing of Staff and Intervenor rebuttal testimony in this proceeding. Additionally, IIWC/FEA/CUB state that even if those two employees are hired, they are offset by two employee departures since May 2016. IIWC/FEA/CUB Ex. 2.0 Rev. at 27. In fact, of the 60 full-time employees hired by IAWC in 2015 and 2016, all 60 of those hires have been offset by 60 resignations during the same time period. *Id.* at 27. IIWC/FEA/CUB argue it is simply unrealistic to assume that these trends will drastically change, and that IAWC will begin to hire employees at a pace that far exceeds employee attrition.

***31** IIWC/FEA/CUB recommend that the Commission adopt Mr. Gorman's adjustment as discussed in his rebuttal testimony and use the last known average level of employees. IIWC/FEA/CUB state that this more reasonable and realistic approach would result in a revenue requirement adjustment of $1,430,877.

e. Commission Analysis and Conclusion

The Commission finds that the Company's estimate of 470 full-time employees is reasonable. The Company projected 482 hires and reduced the projected head count by 2.5%, or 12 positions, to account for vacancies. IAWC's test year staffing level in this case is 26 positions less than IAWC's approved staffing level in Docket No. 11-0767, including anticipated vacancies, and its payroll expense is $300,000 less. IAWC Ex. 2.00 at 19. IAWC cites some of its business initiatives from 2013 which streamlined much of its work and eliminated 16 full-time equivalent positions in 2014 and 2015. No party disputed IAWC's current headcount, or the need for the 24 positions that IAWC seeks to fill. IAWC identified the positions and explained why each is essential to the core functions of IAWC's operations: construction, operation, and maintenance of IAWC's water distribution and wastewater collection systems, meter testing and repair, customer service, and management of the personnel who perform that critical work. IAWC Exhibit 2.01R. The dispute between the parties on this issue is over the vacancy rate. Staff proposes reducing the expense by 5.40%; the AG by 5.77%; and IIWC/FEA/CUB by 7.59%, using the Company's historical vacancy rates since 2014. AG Ex. 1.0 at 12-14; AG Ex. 3.0 at. 7-10; IIWC/FEA/CUB Ex. 1.0 at 9-11; IIWC/FEA/CUB Ex. 2.0 at 23-28; Staff Ex. 3.0 at 14-15; Staff Ex. 11.0 (Rev.) at 10-12.

The Commission finds that the Company's vacancy estimate is reasonable, due in part to the technological improvements affecting the Company's workforce since its last rate case. The Commission notes that neither IIWC/FEA/CUB nor the AG considered any offsetting overtime expense in its adjustment. If the Company cannot fill a budgeted position, current employees must perform the work in overtime, in addition to their other responsibilities. Certainly, any adjustment to the vacancy rate must account for an offset in the amount of overtime paid to employees. The AG and IIWC/FEA/CUB adjustments are rejected, for that reason. Moreover, the AG and IIWC/FEA/CUB adjustments are based on only one month of data, the June 2016 vacancy rate. The Commission agrees with the Company that staffing decisions are much more dynamic than the Company's needs in one month of the year. The Company must have flexibility to hire staff as circumstances demand, to meet service obligations to customers, or deal with unexpected staffing needs, such as main breaks and other emergencies.

Staff witness Kahle's final proposed adjustment did consider an offset for overtime and considered more than one month of vacancy rate data. Staff's proposed adjustment that accounts for overtime also looks at historical vacancy rates since 2014, but it does not consider the recent changes the Company has made to staffing due to the Company's technological advancement projects in 2014 and 2015 which impacted the Company's employee headcount. The Commission finds IAWC's estimate reasonable, because it examines a more recent picture of the Company's vacancy rate.

***32** The AG cites the 2014 American Water Form 10-K in support of its argument that any payroll expense adjustment should not be offset by overtime. The Form 10-K cites main break work due to harsh weather conditions as leading to overtime, and the AG intimates that these main breaks may be part of the reason for increased overtime, not necessarily the vacancy rate. The Commission finds that unanticipated demands on staffing, due to unexpected main breaks, for example, and increased overtime because of fewer employees, go hand in hand. The Company states that it needs to hire additional employees, specifically citing a need for a Field Services Technician, which may have reduced overtime hours in the cases of unanticipated main breaks because there would be more employees overall.

The Commission agrees with the Company that reducing the Company's payroll expense may hinder its ability to successfully recruit and hire qualified individuals. For these reasons, the Staff, AG and IIWC/FEA/CUB adjustments to payroll expense are rejected.

2. Annual Performance Plan Expense (Resolved between IAWC and Staff)

a. IAWC's Position

IAWC explains that part of its Annual Performance Plan ("APP") successfully encourages its employees to achieve IAWC's operational goals—safety, customer satisfaction, environmental leadership, and operational efficiency—with pay that depends on their annual performance as well as that of the Company's. From 2013 to 2015, IAWC states that it reduced safety incident rates and increased customer satisfaction rates, under annual performance pay metrics. IAWC points out that it has so increased its operational efficiency that its overall operating expenses in this case reflect a 3% decrease from those in the Company's 2011 rate case. IAWC asserts that Illinois customers have benefitted from these operational successes.

IAWC notes it initially requested full recovery of its APP expense. However, to narrow the issues, IAWC accepted Staff's proposed adjustment to allow only the portion that encourages IAWC's operational successes. Therefore, IAWC notes, Staff, IAWC, and IIWC/FEA/CUB agree that that portion of the APP expense is recoverable.

IAWC explains that the AG would disallow IAWC's entire APP expense, including the portion that encourages IAWC's operational successes. But, IAWC explains, Mr. Effron does not dispute that IAWC reasonably compensates its employees, or that the APP encourages their operational achievements, or that those achievements benefit Illinois customers. Rather, IAWC points out that the AG focuses on one feature of the APP that ensures that IAWC can fund the plan before payouts are made, and from this alone, the AG claims that the plan expense should be disallowed in its entirety.

IAWC states that when part of the compensation a utility pays its employees is at risk (like incentive or performance pay), recovery of the expense generally hinges on whether it benefits customers. *See, e.g.*, *N. Shore Gas Co.*, Dockets 07-0241/0242 (Consol.), Order at 66 (Feb. 5, 2008) ("The main and guiding criterion is that the [incentive pay] expense be prudent, reasonable and operate in a way to benefit the utility's customers."); *Madigan*, 2011 IL App (1st) 100654 at ¶¶ 51, 55 (affirming the Commission's customer benefit standard). IAWC further explains that the Commission has consistently found that performance pay that promotes safety, increases customer satisfaction, and controls operating expenses benefits utility customers and is rate recoverable. *See* Docket No. 15-0142, Order at 44-46; Docket Nos. 12-0511/12-0512 (Consol.), Order at 130 ("One of the goals that the Commission encourages public utilities to incentivize through [incentive pay] plans is the control and reduction of operating costs since … this should have the effect, all else being equal, of lowering the costs to be recovered in future rate cases.").

***33** IAWC explains that it prudently and reasonably compensates its employees. Like its industry peers, IAWC explains, the Company compensates employees with a mix of base pay, overtime pay, and short- and long-term performance pay. IAWC states that performance pay is pay that varies depending on the individual employee's and the broader Company's performance. IAWC Ex. 9.00R at 4; IAWC Ex. 2.00 at 20. Docket Nos. 07-0241/07-0242 (Consol.), Order at 66 ("Being a large utility means that management depends on the dutiful work performance of its employees. To motivate and maintain high standards, a utility may reasonably offer incentive compensation, as the best way to match both employer and employee interests and to ensure quality work performance."). IAWC further explains that, also like its peers, to compete for talented employees, IAWC targets its employees' total compensation (base pay plus performance pay) at the market median for comparable positions. IAWC Ex. 9.00 at 4-5.

IAWC explains that in 2015 the total compensation it paid its employees was somewhat below both the national and Midwest market medians, by 16% and 15%, respectively. IAWC Ex. 9.00 at 8. IAWC notes that its employees' 2015 base pay alone was substantially below those market medians, by 28% and 25%, respectively. In other words, IAWC maintains that its employees are not overcompensated. IAWC further maintains that if its employees did not receive their performance pay—and received base pay alone—they would be significantly underpaid relative to their peers. *Id.* at 9; IAWC Ex. 7.00R (Rev.) at 23; *Commonwealth Edison Co.*, Docket No. 14-0312, Order at 49-50 (Dec. 10, 2014) (finding the utility should be allowed to recover close to market-level employee compensation, including incentive pay).

IAWC states that it awards its employees short-term performance pay under the APP. IAWC Ex. 2.00 at 20, 22-23; Staff Ex. 3.0, Attach. G at 4-16 (Plan document). The Company explains that payouts under the APP depend 50% on financial performance, assessed via earnings per share metrics, and 50% on operational performance, assessed via safety, customer satisfaction, environmental leadership, and operational efficiency metrics. IAWC Ex. 2.00R (2d Rev.) at 12; IAWC Ex. 9.01 (Rev.) at 7-8. The plan, IAWC states, also requires that IAWC have the financial resources to fund it, assessed as attaining 90% of an earnings per share goal, before payouts can be made. IAWC Ex. 9.00 at 10. IAWC explains, however, that this is not a performance metric under the plan on which employees are paid. *Id.*

IAWC asserts that the APP's operational goals benefit IAWC's customers. In 2013, 2014, and 2015, IAWC explains, its employees achieved incremental and sustained operational successes, under its short-term performance pay Plans. IAWC Ex. 2.00R (2d Rev.) at 12-13.

***34** IAWC asserts that safety incidents decreased, and customer satisfaction and service quality increased. And, IAWC asserts, operational efficiency increased such that the total test year operating expenses that IAWC initially requested in this case—$98.7 million—were 3% less than in its last rate case, despite inflation and despite that, in this case unlike Docket No. 11-0767, IAWC requested recovery of its performance pay expenses. IAWC Ex. 2.00 at 5; IAWC Ex. 2.00R (2d Rev.) at 11; IAWC Ex. 7.00SR (Rev.) at 11. The Company maintains that this reduction has not only mitigated the operating costs that IAWC's customers ultimately pay through rates, but also delayed the time between IAWC's rate cases. IAWC Ex. 2.00R (2d Rev.) at 11-12, 14.

IAWC states that the AG's position to disallow 100% of the APP expense ignores the record evidence and the law and would unfairly disallow the cost of operational metrics that the AG does not dispute benefit customers. First, the AG's position wholly ignores all of IAWC's operational successes, which the APP incentivizes and which unquestionably benefit customers. IAWC Ex. 9.00 at 10. Second, IAWC maintains, the AG's position ignores the structure of the APP itself. IAWC explains that the financial viability aspect of the APP is not a performance metric on which participants are paid.

IAWC also notes that the AG argued that payout under the plan depends on corporate "financial success." As IAWC explained in testimony, 50% of the plan depends on financial performance, and 50%, on operational performance. The 50% financial performance portion of the plan does depend on financial success, IAWC states, measured by achievement of earnings per share goals at threshold, target, and maximum levels. But the 50% operational performance portion does not. And, IAWC states, that is the only portion of the plan at issue here. IAWC reiterates that there is a "financial viability" aspect to the plan: 90% of an earnings per share goal must be attained to ensure IAWC has the financial resources to fund the plan. IAWC explains, however, that is something different than attaining the earnings per share goal itself. In other words, 90% of the target earnings per share target goal falls well below even the threshold earnings per share goal that must be attained for payout under the 50% financial performance portion of the plan. Put simply, IAWC maintains, ""financial viability" is not the same as "financial success."

IAWC notes that, nevertheless, from the financial viability aspect of the APP alone, the AG summarily concluded that "[s]ince payment of the APP is dependent on the achievement of American Water to achieve a threshold financial performance level, the APP primarily benefits shareholders, not ratepayers." IAWC states that the AG, however, never explained why this primarily benefits shareholders, despite all of IAWC's operational successes under the plan, which provide clear and undisputed ratepayer benefits. The Company explains that even if the financial viability aspect of the plan depends on threshold financial success, earnings per share goals only benefit shareholders if those goals are not fixed. IAWC Ex. 7.00R (Rev.) at 28. A utility must reduce or control its operating expenses (which benefit customers) to reach its earnings per share goals. If the utility's expenses are excessive, IAWC explains, it simply cannot realize the profits necessary to satisfy its investors. *Id.*

***35** IAWC points out that the AG's position also ignores that, despite the financial viability aspect of its short-term performance pay plans, IAWC's employees have consistently received performance pay under the plans every year, for at least the last seven years. IAWC-AG Stip. Cross Ex. 2.00 at 2. In fact, IAWC states, on average, payouts have exceeded the target level—the level at which IAWC set performance pay in its revenue requirement in this case. *Id.*; IAWC Ex. 2.00 at 21. IAWC explains that this means that IAWC employees can reasonably be expected to meet or exceed their APP operational goals in the test year; IAWC can reasonably be expected to award them for that performance; and customers can reasonably be expected to benefit, the financial viability aspect of the plan aside. *See N. Shore Gas Co.*, Docket Nos. 07-0241/07-0242 (Consol.), Order at 67 (Feb. 5, 2008).

IAWC also states that the Commission consistently approves cost recovery for performance pay operational metrics that benefit customers, such as safety, customer satisfaction, and operational efficiency. *See* Docket Nos. 07-0241/07-0242 (Consol.), Order at 66 (when incentive pay tied to "matters of customer service, customer satisfaction, the reduction of operating expenses, and the like is at hand, it is incumbent upon the Commission to take a close and considered view"). IAWC points out that these are the very goals that the APP incentivizes, to the undisputed benefit of IAWC's customers in 2013, 2014, and 2015.

Moreover, IAWC continues, in recognizing that operational performance pay metrics benefit customers, the Commission has approved cost recovery even when the governing plan includes a financial feature, to avoid an unjust and disproportionate result. *See* Docket No. 14-0312, Order at 48-51. IAWC explains that in Docket No. 14-0312, the Commission approved partial recovery of ComEd's Annual Incentive Plan, which consisted of eight operational metrics on which ComEd employees received annual incentive pay as well as a ""Shareholder Protection Feature" that relied on a reference to Exelon's earnings per share performance. *Id.* IAWC explains that like the financial viability feature of IAWC's APP, ComEd's Annual Incentive Plan's Shareholder Protection Feature could limit the amount of annual incentive compensation paid, but it was not a metric on which ComEd employees earned their annual incentive compensation. *Id.* at 29. IAWC explains that in Docket No. 14-0312, like here, no party disputed that ComEd's Annual Incentive Plan metrics incented employees to meet goals that are beneficial to ratepayers. *Id.* And in that case, like here, the record showed that if employees did not receive their annual incentive pay, they would receive below market wages. *Id.* In light of this, IAWC explains, the Commission found that ComEd should recover its Annual Incentive Plan costs, at 102.9% payout, which the Commission concluded "insures that ComEd recovers the market-based salary for their employees plus a reasonable bonus which further serves to encourage employees continued achievement of the operational goals to the benefit of ratepayers, without allowing for excess cost recovery." *Id.* at 50. IAWC explains that the Commission rejected the AG's proposed 100% disallowance of ComEd's Annual Incentive Plan in Docket No. 14-0312—based only on the existence of the Shareholder Protection Feature—as disproportionate. *Id.* at 49.

***36** Besides ignoring the Docket No. 14-0312 Order, IAWC argues that the AG disregards that the operational portion of the APP depends on operational successes, not on financial goals. IAWC notes that the AG cited, in support of its argument, the Commission's order from IAWC's 2007 rate case, where the Commission found: "the Commission has generally disallowed such expenses *except where the utility has demonstrated that its incentive compensation plan has reduced expenses and created greater efficiencies in operations which provide net benefits to ratepayers*." Docket No. 07-0507, Order at 25 (emphasis added).

Still, IAWC notes, rather than recognizing all of the customer benefits that IAWC's APP provides, the AG faulted IAWC for its inability to show that its reduced operating expenses are not the result of something else, like declining usage or investments in innovative technology. IAWC explains that showing that performance pay is "directly responsible" for operational successes like reductions in operating expenses, however, as the AG advocates, is not the Commission's cost recovery standard. To avoid a disproportionate result, IAWC states the Commission should accept Staff's adjustment to allow 50% recovery of the APP expense.

b. Staff's Position

Staff's proposed adjustments remove incentive compensation expenses that are based on underlying financial goals that primarily benefit shareholders. Staff states that ratepayers should not be required to fund incentive compensation plans linked to the financial performance goals of the Company. Staff's adjustments cover operating expenses for the 2017 test year. Staff Ex. 3.0 at 10-14.

The Company accepted Staff's proposed adjustment for test year operating expenses with the only caveat being the adjustment for payroll taxes. IAWC Ex. 7.00SR (Rev.) at 10-11. Staff later modified its adjustment to reflect the correct amount of payroll taxes as supplied by the Company. IAWC-Staff Stip. Cross Ex. 1.00 at 17 and 19. The Company included the 2017 test year operating expense adjustment in its surrebuttal revenue requirement. IAWC Ex. 4.02SR (Rev.), column "t". Staff adopts the Company's surrebuttal calculation for the adjustment to the non-capitalized portion of incentive compensation expense.

c. AG's Position

The AG recommends that 100% of the cost of IAWC's performance plans be disallowed because no payment can be made to any participant in the APP, or short-term variable compensation program, unless the corporate financial performance of IAWC's corporate parent achieves at least 90% of the targeted earnings per share. According to the AG, therefore, the payout of APP to its participants is dependent upon the financial success of each of the affiliates of IAWC, not just IAWC. Since payment of the APP is dependent on the achievement of American Water to achieve a threshold financial performance level, the APP primarily benefits shareholders, not ratepayers. AG Ex. 1.0 at 14-15.

***37** The AG argues that the Commission has consistently and routinely found that it is inappropriate to include in rates the costs associated with incentive compensation programs that condition payment on corporate financial goals. *Id.* For example, in the Company's prior rate case, Docket No. 11-0767, IAWC did not oppose a Staff adjustment to remove a portion of the cost of the performance plan that the Company inadvertently had not removed. Docket No. 11-0767, Order at 48. And in a prior IAWC rate case, the Commission disallowed all costs of the performance plans, finding that: The Commission has consistently disallowed recovery of payouts that are tied to overall company financial goals. As is apparent from previous rate orders, the Commission has generally disallowed such expenses except where the utility has demonstrated that its incentive compensation plan has reduced expenses and created greater efficiencies in operations which provide net benefits to ratepayers. In this case, no such showing has been made by IAWC.

… In no way does the Commission mean to suggest that IAWC should not be using an incentive compensation plan. On the contrary, if use of the APP helps IAWC meet its financial goals as well as minimum statutory and regulatory requirements, the Commission has no objection to its continued use. The Commission, however, does object to the notion that ratepayers should have to help encourage IAWC's employees to meet goals benefitting shareholders and meet minimum service obligations.

Docket No. 07-0507, Order at 25-27.

The AG argues that IAWC's reliance on the Commission's Order in Docket No. 14-0312 as support for its position that it should be allowed to recover incentive compensation costs for a plan that requires the attainment of certain financial goals for employees to receive payment is misplaced. The AG points out that the Commission's Order in that case shows that the Commission does not consider conditioning incentive compensation costs on the attainment of financial goals as prudent or reasonable.

The AG notes that in its Order in Docket No. 14-0312, the Commission directed ComEd to develop an incentive compensation plan that was not based on the earnings per share or any other financial performance metric of ComEd's corporate parent, Exelon. The Commission ordered a revised plan to be presented in ComEd's next formula rate update or the Company would run the risk of continued disallowance of such expenses. The AG further states that Docket No. 14-0312 is unlike this case in fundamental ways. Docket No. 14-0312 was a ComEd formula rate update case. ComEd's formula rates under Section 16-108.5 of the Act differ from IAWC's rates determined under Section 9-201. For example, formula rates are only in effect for one year while IAWC's rates will be in effect for an unknown period of time. Moreover, there has been no analysis to determine the differences between ComEd's incentive pay plan considered by the Commission in Docket No. 14-0312 and IAWC's plan under consideration in the instant proceeding.

***38** The AG points out that the Company has not shown any link between the APP tied to financial goals and any identified reduction in operation and maintenance expenses or delay in the filing of rate cases or, further, that these efficiencies would not have been achieved in the absence of incentive compensation based on financial goals. Mr. Effron argued that many factors, such as weather, water usage, and technology, can affect changes in expenses or the time between rate cases. AG Ex. 3.0 at 10-11. In addition, rate changes, such as the use of a Qualifying Infrastructure Plant ("QIP") rider, may affect the frequency of rate cases. Other than general assertions, the AG asserts that the Company has provided no evidence that the incentive compensation program has affected the results of operations or its revenue increase request.

Moreover, the AG notes that other IAWC witnesses identified reasons for reduced expenses that have nothing to do with the existence of the APP. Company witness Roach stated: "Over the long term, *reduced usage per residential customer has helped lower operating costs*, and has helped avoid some capacity-related needs. These savings and avoided costs have benefitted customers through the ratemaking process." IAWC Ex. 8.00 at 14 (emphasis added). Mr. Roach added: "As a result of … ongoing reductions in water usage, the water utility industry has avoided the need to build supply, treatment, and transmission facilities to meet those now avoided additional usage demands." *Id.* at 14-15. Company witness Hauk stated:

> And our water efficiency efforts are demonstrated by investments in new metering and innovative data collection technologies, and by improved business processes that help us work smarter and more efficiently and, by extension, contribute to our cost control efforts. Our ability to reduce O&M from the level approved in our 2011 rate case proves the effectiveness of these efforts, and the consequent cost benefit to our customers.

IAWC Ex. 1.0 at 12.

The AG concludes that the Commission should adopt the AG's adjustment to remove the remaining 50% of the APP because the Company has not established that the APP has been directly responsible for any reduction in operation and maintenance expenses or a delay in the filing of the current rate case or that these cost reductions would not have been achieved in the absence of incentive compensation based on financial goals.

d. Commission Analysis and Conclusion

At issue is whether the Company may recover 50% of its expenses paid to fund its APP. IAWC initially sought recovery of 100% of its expenses related to its incentive compensation program; however, after Staff questioned the portion of the Plan which is based on financial goals and metrics, the Company withdrew its request for full recovery. IAWC Ex. 2.00R (2d Rev.) at 12; IAWC Ex. 9.01 (Rev.) at 7-8; Staff Ex. 3.0 at 10-14. The remaining 50% of the metrics in the Plan are tied to operational outcomes, and no party disputes that they are not related to financial goals. The AG requests that the Commission remove all expenses related to the Company's APP because no payment can be made to any participant in the APP unless the corporate financial performance of IAWC's corporate parent achieves at least 90% of the targeted earnings per share. Because of this overall requirement, the AG argues that the Plan is completely tied to financial goals, which the Commission does not consider prudent or reasonable. AG Ex. 1.0 at 14-15.

***39** A utility's incentive compensation plan is often one component of employee salaries, with pay depending on both employee and utility annual performance. Generally, reasonable and prudent expenditures for salaries paid by the utility should be recoverable from ratepayers and should be included in the utility's rate base. *Madigan,* 2011 IL App. 1st 100654 at ¶ 52. Under certain circumstances, however, it has been held that the cost of salaries should be apportioned between shareholders and ratepayers. *Commonwealth Edison Co.,* 398 Ill.App.3d at 517, *citing Du Page Utility Co. v. Ill. Commerce Comm'n,* 47 Ill.2d 550, 560-61, (1971), *Candlewick Lake Utilities Co. v. Ill. Commerce Comm'n,* 122 Ill.App.3d 219, 226 (1983). For example, the Commission has required that the utility must demonstrate a sufficient nexus between the earnings per share portion of the employee incentive compensation plan and a benefit to ratepayers. *Commonwealth Edison Co.*, 398 Ill.App.3d 510 at 515.

The Commission agrees with the AG that when incentive compensation seeks to achieve goals that primarily benefit shareholders, it is reasonable to require that shareholders bear the cost of that incentive compensation. In a recent Peoples Gas/North Shore rate case, the Commission stated that "incentive compensation related to financial goals, affiliate goals or shareholder goals should not be recoverable from ratepayers." Docket Nos. 09-0166/0167 (Consol.) Order at 58.

In this case, however, the Company is only including the expenses associated with operational metrics. Fifty percent of the goals in IAWC's APP are related to safety, customer satisfaction, technology, and operational efficiency. Staff Ex. 3.0, Attachment G at 9 (Conf.). The remaining 50% are associated with the Company's financial growth, targeting a specific earnings per share. The Commission notes that no party disputes that the APP's operational component is designed to benefit ratepayers. Certainly benchmarks that require reducing OSHA injuries, meeting drinking water quality standards and increasing customer satisfaction survey results directly benefit IAWC's ratepayers. *Id.* This is the crux of the analysis concerning whether a utility can recover its expenses related to incentive compensation plans. While it is true that there is a financial aspect to the plan in that 90% of an earnings per share goal must be attained to ensure IAWC has the financial resources to fund the plan, the Commission agrees with IAWC that this is something different than attaining the earnings per share goal itself.

***40** This case can be distinguished from ComEd's formula rate case, Docket No. 14-0312, which is governed by EIMA, Section 16-108.5 of the Act. Section 16-108.5 specifically permits recovery of incentive compensation that:

> is based on the achievement of operational metrics, including metrics related to budget controls, outage duration and frequency, safety, customer service, efficiency and productivity, and environmental compliance. *Incentive compensation expense that is based on net income or an affiliate's earnings per share shall not be recoverable under the performance-based formula rate*;

220 ILCS 5/16-108.5(c)(4)(A). As stated earlier in this Order, Section 16-108.5 does not apply to this rate case. EIMA, and specifically Section 108.5(c)(4)(A), does not govern IAWC, because it is not a "participating utility" under the Act. EIMA's specific language disallowing expense that is ""based on net income" or "earnings per share" is not relevant to this case. EIMA expressly disallows incentive compensation expenses based on financial indicators. For this case, the Commission is bound by Article IX and the Illinois Courts' prior discussion of incentive compensation. The Commission finds that since IAWC's APP is reasonable, and the recovery of the expense is limited to only the operational metrics benefitting ratepayers, such recovery is appropriate.

Finally, the Commission points out a reluctance to disallow 100% of the incentive compensation expense because the APP payout is a component of market value employee salaries that would typically be recoverable. As IAWC notes, it currently pays its employees below market value. By disallowing recovery of 100% of employees' incentive compensation, the Company may decide it can no longer offer an APP to its employees, bringing IAWC's employee compensation even lower than its competitors and making it difficult for the Company to attract and retain qualified personnel.

3. Purchased Power Expense

a. IAWC's Position

IAWC explains that it relies on electricity to power its buildings, pumping stations, and treatment plants. Like many large consumers of electricity, the Company hedges its electricity costs by entering into power supply agreements. IAWC Ex. 2.00R (2d Rev.) at 15. IAWC explains that rates under these agreements are based on the wholesale price of energy and capacity in the PJM Interconnection LLC ("PJM") and Midcontinent Independent System Operator ("MISO") regions. IAWC further explains that the capacity component is based on annual auctions. *Id.*

IAWC states that its test year purchased power expense is based on two power supply agreements (one each for MISO and PJM), which the Company entered into during September of 2015. IAWC Ex. 4.00 at 13. IAWC adjusted its original 2017 forecast, prepared before September 2015, by $219,000, to account for these agreements, including MISO capacity cost increases. IAWC explains that capacity costs account for 15-20% of total retail power costs under the September 2015 power supply agreements. *Id.*

***41** IAWC explains that after it filed this case, MISO announced lower capacity costs for MISO's June 1, 2016 through May 31, 2017 planning year. Based on this alone, IAWC notes that the AG argued that purchased power expense should be reduced by the entire $219,000 adjustment that IAWC made, to account for these new capacity prices. AG Ex. 1.0 at 20-21.

IAWC argues that the AG's adjustment is overstated in two ways. First, IAWC explains, lower capacity prices will go into effect only in the MISO region, and only then for half of the test year—through May 2017. IAWC Ex. 2.00R (2d Rev.) at 16. Second, IAWC states, the AG's proposed adjustment to reflect a capacity cost decrease does not account for increases in other components of IAWC's purchased power costs, including increases in Ameren and ComEd distribution rates, which comprise its $219,000 adjustment. IAWC Ex. 2.00R (2d Rev.) at 17.

IAWC also maintains that the AG's adjustment is too narrow. The AG's adjustment simply assumes that capacity prices for the final seven months of the 2017 test year will continue at the level announced for the first half of 2017, but IAWC maintains that there is no reason to believe that this will be the case. IAWC Ex. 2.00R (2d Rev.) at 16. IAWC explains that recent history shows that MISO capacity prices have been extremely volatile: costs for the 2013-2014 planning year were $1.05/megawatt day; they rose to $16.75/megawatt day in 2014-2015; prices rose again, significantly, to $150/megawatt day in 2015-2016; and then fell to $72/megawatt day for the 2016-2017 planning year. *Id.* at 15; AG Ex. 1.0 at 20-21. IAWC states that these dramatic swings highlight the likelihood that capacity charges will increase again in the latter seven months of 2017. And if that happens, IAWC explains, the AG's adjustment would shortchange IAWC's full recovery of purchased power costs. IAWC Ex. 2.00R (2d Rev.) at 16-17.

IAWC maintains that the Commission should reject the AG's adjustment and approve recovery of IAWC's purchased power expense, as adjusted by IAWC to reflect its September 2015 power supply contracts.

b. AG's Position

The AG states that IAWC included electricity capacity charges in its purchased power expense. In 2015-2016 the capacity charges in the MISO area that serves some IAWC facilities jumped from $16 to $150 for June 1, 2015 through May 30, 2016. In 20162017, the capacity charge dropped to $72. AG Ex. 1.0 at 20-21. Despite the more than 50% decrease in capacity costs for the 2016-2017 period, IAWC increased the MISO capacity charge in its test year. AG witness Effron removed the part of the Company's pro forma adjustment to fuel, power, and chemical expense that increased production costs from the high $150 capacity charge in 2015-2016. Mr. Effron testified that the Company's pro forma adjustment to increase the purchased power costs over the 2017 projected level was not supported and using the 2015-16 capacity charge of $150 would likely overstate IAWC's purchased power costs. AG Ex. 1.0 at 20; AG Ex. 3.0 at 13.

***42** The AG points out that Company witness Smyth testified that he "…agrees that, due to the capacity price flow-through, if viewed in isolation, IAWC will temporarily benefit from the reduction in capacity prices in the [MISO] territory from June 1, 2016 through May 30, 2017." Mr. Smyth argued that there is no assurance that prices will not swing up again in the second half of the test year when MISO holds it capacity auction for the 2017-2018 planning year. IAWC Ex. 2.0 at 14-17. AG witness Effron agreed that while there is no assurance that prices will not swing up in the second half of 2017, there is also no assurance that the prices will go down in the second half of 2017. AG Ex. 3.0 at 13. Moreover, the AG points out that Mr. Effron's adjustment did not change the Company's original forecast for 2017 power costs that considered several factors including the $150 per megawatt-day passed through MISO capacity price that was in effect through May 30, 2016.

The AG adjustment is conservative in that it only removes the Company's pro forma adjustment to increase the costs greater than the projected 2017 power costs that were based on the $150 per megawatt-day pass through MISO capacity price, despite the fact that, as noted above, MISO capacity prices have decreased by more than 50% to $72 per megawatt/day for 2016-2017. The AG recommends that the Commission adopt the AG adjustment to reduce the test year power costs $219,035.

c. Commission Analysis and Conclusion

The Commission agrees with the Company that the AG's adjustment would not allow IAWC to recover its purchased power costs. The Commission also agrees that MISO's dramatic price swings over the last few years indicate a likelihood that prices will continue to fluctuate significantly. Therefore, the Commission declines to make the AG's proposed adjustment.

4. Test Year Sales Level

a. IAWC's Position

The Company explains that because utility rates incorporate a volumetric charge, the total sales volumes must be forecasted to ensure that rates will recover the total revenue requirement. IAWC explains that the objective in a future test year case is to forecast sales as accurately as possible, so that the forecast reflects actual conditions in the test year, and the utility can set rates that allow it to earn its authorized revenues.

The Company states that it is undisputed that its sales volumes are declining. IAWC Ex. 8.00SR at 6, Table 8.02. IAWC estimates that the decline in use per residential customer is approximately 2.03% per year while use among commercial customers is declining at a rate of 0.4% per year. IAWC Ex. 8.00 at 6.

IAWC explains that the decline in residential and commercial usage is driven by customers' installation of new low-flow fixtures and appliances, as well as customer awareness of water conservation and efficiency initiatives. IAWC Ex. 8.00 at 9-11. IAWC further asserts that federal law mandates water efficiency standards for fixtures and appliances, which have been growing more stringent over time. *Id.* at 11. IAWC states that more than 87% of homes in Illinois were constructed before federal water efficiency standards took effect, and were constructed with more water-intensive fixtures. The Company explains that as customers replace older water-intensive fixtures with fixtures that meet the federal mandates, their demand for water declines. *Id.* at 11-12. IAWC states that, therefore, usage will likely continue to decline through the 2017 test year— and beyond. IAWC Ex. 8.00R (Rev.) at 4.

***43** The Company states the decline is significant, both in terms of gallons and in terms of revenue dollars. From 2006 through 2015, IAWC states it sold 17.8 billion fewer gallons than was used to determine its Commission-approved revenue requirements. IAWC Ex. 8.00 at 15. IAWC explains that while over 60% of IAWC's revenues are variable— recovered via per-gallon volumetric charges— over 90% of the Company's costs are fixed. IAWC Ex. 7.00 at 6-7. IAWC states that when customer usage and sales volumes decline, as IAWC's have, and its rate structure relies heavily on volumetric charges, as IAWC's does, the rates do not produce enough revenue to cover the utility's costs. *Id.* at 5. Because IAWC's rate structure relies heavily on volumetric charges, IAWC explains, this shortfall in gallons sold led IAWC to under-recover its approved revenue requirements by approximately $51 million between 2006 and 2015. *Id.* at 6; IAWC Ex. 8.00 at 15.

IAWC states that it developed its forecasted test year sales volumes by conducting a statistical regression analysis using base usage data. IAWC Ex. 8.00 at 5-6. The Company explains that a regression analysis is the best method for modeling a trend in data, because the analysis estimates the relationship between variables—in this case, time and usage per customer. IAWC Ex. 8.00SR at 3. IAWC explains further that a regression analysis calculates a trend line that best matches and incorporates singular data points—in this case, data points representing usage per customer at particular points in time. *See* IAWC Ex. 8.01; IAWC Ex. 8.02. The Company points out that both IIWC/FEA/CUB witness Gorman and IIWC/FEA witness Collins agreed that a regression analysis is the appropriate method for calculating a trend in data. IAWC Ex. 8.00SR at 3.

IAWC states that its regression analysis relied on a robust data set and produced reliable results. The data set, IAWC explains, includes the average usage per customer per day in each month, for each customer in the residential and commercial classes, over the 10-year period 2006 through 2015. IAWC Ex. 8.00 at 5. IAWC states the 10-year period is appropriate because, in statistics, a greater number of observations — a larger data set — yields more significant explanatory values. IAWC Ex. 8.00R (Rev.) at 10.

For purposes of conducting the regression analysis, IAWC states that it excluded weather-dependent usage from its data set. IAWC Ex. 8.00 at 7-8. IAWC explains that it is necessary to separate weather-sensitive usage from base usage in order to ensure that the result of the analysis (the trend line) measures only trends that exist independently from fluctuations in weather. IAWC Ex. 8.00SR at 4. In addition, IAWC states that unlike an analysis based on weather normalization, which requires an assumption that weather in the forecasted period will be equal to “normal” weather, an analysis of base usage does not require the Company or the Commission to make any assumptions regarding weather during the forecasted period because it considers only usage that is not driven by weather. *Id.* at 7.

***44** The Company opines that the results of IAWC's regression analysis are reliable. IAWC explains that the trend line that resulted from the regression has a 99.5% chance of correctly predicting usage in the test year. *Id.* at 2. In other words, IAWC explains that there is a 0.05% chance that usage in the test year will be significantly different than usage predicted by IAWC's regression analysis.

IAWC notes that although all parties agree that IAWC's residential sales volumes are trending down, the parties disagree about how the decline should be forecasted into the test year. IAWC understands that Mr. Gorman and Mr. Collins argue that residential usage in the test year should be assumed to be equal to average usage over the 2011-2015 period, while commercial usage in the test year should be set equal to usage in 2015. IAWC states that, despite IIWC/FEA/CUB's agreement that a regression analysis is an appropriate method for analyzing trends in data, and their presentation of a regression analysis in briefs, IIWC/FEA/CUB argue that a simple average of monthly usage over the five-year period 2011-2015 is a suitable predictor of residential usage in the test year, and that the entire regression analysis should be ignored when forecasting commercial usage. IAWC states that these contentions must be rejected.

IAWC explains that an average cannot account for a trend in the data being averaged. Consider the example provided by IAWC witness Roach: the simple number set 12, 11, 10, 9, 8 represents a trend. “Given the trend, the next number in the set would logically be 7. But if one were to average the data points, as Mr. Gorman and Mr. Collins did, the result would be 10.” IAWC maintains that this same logic holds true here. IAWC states that usage has already declined below the level Mr. Gorman and Mr. Collins proposed to incorporate into the forecast.

IAWC states that because the data Mr. Gorman and Mr. Collins relied upon in developing their average includes weather-sensitive usage, it requires acceptance of the inherent assumption that weather in the forecasted period will be similar to weather in the averaged period. IAWC explains that because water usage is driven in large part by precipitation, rather than primarily by temperature (like electric and natural gas usage), there is no generally-accepted weather normalization methodology in the water industry. IAWC Ex. 8.00 at 8. Therefore, IAWC states, Mr. Gorman's technique of averaging five years of usage as an attempt to normalize for weather is arbitrary.

In addition, IAWC states, Mr. Gorman's contention that weather during the 2011-2015 period was “relatively close to normal” is incorrect, based on data. IIWC/FEA/CUB Ex. 1.0 at 7. The Company explains that during 2012, weather in Illinois was unusually hot and dry; it was between 25 and 30% warmer than the 40-year average and between 34 and 60% drier than the 40-year average. IAWC Ex. 8.00R (Rev.) at 6. But, IAWC points out, data from 2012 represents one-fifth of the data upon which Mr. Gorman's analysis relied. IAWC states that Mr. Gorman's approach is unreasonable because it assumes that weather in the test year will correspond to weather during the five-year period he averaged, but that period includes extraordinary weather. In contrast, the Company states its analysis, which relied on data regarding base usage, requires no such assumptions regarding weather in the forecasted period. IAWC Ex. 8.00SR at 7. As such, IAWC argues, its approach is a far more reliable basis for a forecast. IAWC Ex. 8.00 at 8.

b. Staff's Position

***45** Staff states in testimony that it reviewed the Company's methodologies for forecasting annual use per residential customer and the number of residential customers per month. Staff agrees with the Company's methods for forecasting the number of customers per month but was less certain about the method used to forecast the declining sales trend. Staff states that IAWC's method is unnecessarily complex and relies on some assumptions that may or may not be valid. Staff witness Brightwell noted that he used alternative methods which lead to qualitatively similar results. Based on the data provided by the Company, Staff states the evidence supports a hypothesis of a downward trend in average monthly use per residential customer. Staff Ex. 8.0 at 5.

c. IIWC/FEA/CUB Position

IIWC/FEA/CUB witness Gorman plotted a trend using average data from five full years' worth of water usage data and concluded that, though residential base water use has declined over the past ten years, the rate of decline has slowed in recent years. IIWC/FEA/CUB Ex. 2.0 (Rev.) at 2. Mr. Gorman explains that a forecast based on the most recent five years of usage is more likely to be accurate than a forecast based on ten years of usage because the decline in residential base water use per customer has not been as steep over the past five years as compared to the five years prior to that. IIWC/FEA/CUB also observe that Commercial water use has not declined at all in the past ten years — it has been stable, or even slightly increasing. IIWC/FEA/CUB Ex. 2.0 (Rev.) Figure 3 at 6.

It is IIWC/FEA/CUB's position that the Company's analysis of residential and commercial sales trends is flawed. The result of IAWC's analysis was considerably lower than the most recent five-year average for both residential and commercial customer classes. *Id.* at 7. It is the opinion of IIWC/FEA/CUB that it is a more reasonable approach to use an averaging of the most recent five years of data than the most recent ten years of data because the trends show that conservation actions and economic conditions that may have had a greater impact five-to-ten years ago have largely leveled off in the last five years. IIWC/FEA/CUB Ex. 2.0 at 8.

IIWC/FEA/CUB note that Company witness Roach claims that the weather patterns during 2011-2015 were not representative of test year weather. To justify this conclusion, however, IAWC examined Heating Degree Day (“HDD”) and Cooling Degree Day (“CDD”) data only for June, July and August at Champaign and Springfield. IAWC Ex. 8.00R at 8. This limited data is not representative of normalized weather conditions for Illinois, according to IIWC/FEA/CUB. IIWC/FEA/CUB witness Gorman reviewed the historical HDD and CDD data for all months of the year, which showed that the weather and rainfall for 2011-2015 was in fact more representative of normalized weather conditions for Illinois than Mr. Roach's data. IIWC/FEA/CUB Ex. 2.0 (Rev.) at 7.

***46** Furthermore, though IAWC witness Roach criticized Mr. Gorman's use of data from the whole State of Illinois as being skewed toward the cooler Chicago region (IAWC Ex. 8.00SR at 12), IIWC/FEA/CUB claim it is Mr. Roach's analysis that improperly excludes large areas of IAWC's service territory.

IIWC/FEA/CUB witness Gorman calculated an increase in residential and commercial revenue from the Company's estimation at current rates of $3.335 million and $1.15 million, respectively, net of variable chemical and power expenses, which increase with increased sales. IIWC/FEA/CUB Ex. 1.0 at 8.

d. Commission Analysis and Conclusion

No party disputes that water usage is declining. The parties dispute how to forecast the total customer sales level in 2017. Though the parties appear to agree that a regression analysis is the best way to plot large data sets of water usage, only the Company used such an analysis. Despite IIWC/FEA/CUB's acknowledgment that a regression analysis is the proper tool for modeling such data, it used an average of the last five years of usage data. IIWC/FEA/CUB Ex. 2.0 (Rev.) at 2. In testimony, Staff questioned the Company's methodology, but Staff's analysis produced estimates similar to that of the Company. Staff Ex. 8.0 at 5. Staff did not brief this issue.

The Commission agrees with the Company that a regression analysis using the last ten years of data is the most appropriate method to calculate customer usage. The trend line that resulted from its regression analysis has a 99.5% chance of correctly predicting usage in the test year. The Commission notes that IIWC/FEA/CUB's use of a five-year analysis produces an average that is higher than any actual usage during that five-year period, which is not reasonable. Moreover, the Commission agrees with the Company that separating weather sensitivity from its initial analysis ensures that the trend lines only measure trends that exist independently from fluctuations in weather.

The Commission agrees with the Company that IIWC/FEA/CUB's analysis using weather includes a year (2012) where weather was abnormally hot and dry. IAWC then claims IIWC/FEA/CUB incorrectly samples weather data from only certain areas of the State, ignoring locations where it serves significant portions of its ratepayers, such as downstate or in Central Illinois. IIWC/FEA/CUB criticizes the Company's subsequent analysis only using weather data from the summer months, when discretionary summer outdoor usage is variable. The Commission finds both these analyses flawed.

For these reasons, the Commission finds the Company's initial analysis which ignores weather trends and examines only usage data produces the most reasonable estimate of test year sales level. As for commercial usage, the Commission disagrees with IIWC/FEA/CUB that using the 2015 actual usage rate among commercial users is more appropriate than the regression analysis the Company performed. Again, the Company's regression analysis which captures the declining usage over the last ten years, albeit smaller than the decline among residential customers, provides a more reasonable estimate for the future test year. The adjustments proposed by IIWC/FEA/CUB are not adopted.

5. Uncollectible Rate in Lincoln

a. IAWC's Position

***47** IAWC states that, to provide a reasonable, consistent approach across its service territories, the Company used a 0.95% uncollectible rate for its four districts: Zone 1, Chicago Metro-Wastewater, Lincoln and Pekin. IAWC understands that AG witness Effron, however, proposes a separate uncollectible rate of 0.92% for the Lincoln district only. AG Ex. 1.0 at 5. IAWC explains that maintaining separate uncollectible rates for each rate zone adds to the complexity of preparing a rate case and preparing the Company's annual business plan. IAWC Ex. 4.00R at 15. The Company states it also, for example, used one set of depreciation rates for all rate zones, rather than preparing multiple costly depreciation studies. The Company states its use of one uncollectible rate to forecast uncollectibles for the entire Company is similarly reasonable, and the use of one uncollectible rate, and one gross revenue conversion factor, for all tariff groups is consistent with the Company's last rate case, Docket No. 11-0767, and previous rate cases, Docket Nos. 07-0507, 02-0690, and 00-0340.

IAWC states that Mr. Effron's proposal is also unnecessary, as it reduces the Lincoln rate zone revenue requirement by less than $1,500, or $0.01 per typical residential customer bill. IAWC Ex. 4.00R at 15. The Company maintains that Mr. Effron's proposal should be rejected.

b. AG's Position

The AG states that IAWC applied a uniform Gross Revenue Conversion Factor (“GRCF”) to all of its divisions to avoid the complexity of maintaining separate uncollectible rates for each zone. The AG argues that the Company has a history of maintaining separate uncollectible rates for its various divisions. For the projected 2017 test year, the calculated uncollectible rate for Lincoln was 0.92% while the uncollectible rate for the other divisions were 0.95%. For projected

2016, the calculated uncollectible ratio for Chicago Metro-Wastewaster was 0.880% while the uncollectible ratios for the other divisions were 0.900%. The AG notes that for 2014 and 2015, the actual uncollectible ratios differ for all divisions. AG Group Ex. Part 1 at 61, IAWC Schedule C-16 Line 23.

The AG asserts that a separate GRCF for each district is appropriate. Having four GRCFs rather than one GRCF adds little complexity for a rate case when there are already separate revenue requirements for each district. Moreover, doing so would be consistent with the Commission's finding in a prior IAWC rate case, Docket No. 09-0319, where the Commission concluded that the uncollectible factor used in the GRCF should be different for each district. The Order stated:

> The Commission also finds convincing [AG's] assertion that its proposal to calculate a district-specific uncollectibles factor produces a more accurate estimate of the district specific revenue requirement.

***48** Docket No. 09-0319, Order at 60.

The AG concludes that the Commission should approve the use of a separate GRCF for the Lincoln division so that consumers in that division can benefit from the lower uncollectible rate in that area.

c. Commission Analysis and Conclusion

The Commission agrees with the AG that IAWC's Lincoln customers should benefit from the lower 2017 test year estimated GRCF, regardless of the small impact it will have on customers' bills. This is consistent with past Commission practice. The Commission disagrees that district-specific uncollectibles rates are unnecessarily complex. The Company is directed to use the 0.92% uncollectible rate for the Lincoln water district.

6. Demand Study Costs

a. IAWC's Position

IAWC states that the Company and the AG agree that IAWC's direct measurement demand study be discontinued. The AG recommends that the Company's revenue requirement be reduced by approximately $69,000 for test year demand study costs. AG Ex 2.0 at 16-17; AG Ex. 4.0 at 1-2. IAWC states that this adjustment is unnecessary. IAWC notes that Mr. Rubin is correct that IAWC expects to incur this amount for demand study data collection and analysis in 2017. IAWC Ex. 4.00R at 19; IAWC Ex. 4.00SR at 11. But, IAWC states, these costs are accounted for as deferred expenses, so they are not reflected in the test year revenue requirement, and IAWC is not seeking to recover them in the current rate case. IAWC Ex. 4.00R at 19; IAWC Ex. 4.00SR at 11-12. As a result, IAWC points out that Mr. Rubin has proposed to disallow costs that are already not in the test year. IAWC states that no adjustment is needed to remove an amount that is not reflected in the test year. IAWC Ex. 4.00SR at 12.

b. AG's Position

In direct testimony, AG witness Rubin testified that he agrees with IAWC's request to discontinue collecting demand data, stating that the demand data the utility has gathered for this case should be usable for many years going forward. AG Ex. 2.0 at 16. Accordingly, Mr. Rubin recommends that the Company's revenue requirement be reduced by $69,460. *Id.* at 16-17; AG Ex. 2.7.

In rebuttal testimony, AG witness Rubin explained that in a response to discovery, IAWC stated the amount it would save by no longer collecting demand data. The $69,460 number is the basis for Mr. Rubin's proposed reduction to the revenue requirement. However, in its rebuttal testimony, the Company did an about-face and claimed that there are no savings associated with discontinuing collecting demand data because the expenses are deferred, and not considered a current cost of service. IAWC should be held to its first position, that is, that $69,460 should be removed from its revenue requirement request. In its direct case, Company witness Kaiser testified that "IAWC would accept an adjustment to test year expenses to remove the cost related to the collection and compilation of the direct measurement data if the Commission approves discontinuance of the data collection." IAWC Ex. 3.00 at 31-32. And, in responding to the AG's data request, the Company quantified the amount associated with collecting the demand data that should be removed from the revenue requirement.

***49** The AG argues that the Company's change in position in rebuttal testimony responded to no party. No party opposed IAWC's proposal to discontinue collecting demand data and to remove the associated costs from its proposed revenue requirement. Therefore, the AG requests that $69,460 be removed from the revenue requirement approved in this case.

c. Commission Analysis and Conclusion

The parties all agree that IAWC's demand study be discontinued. The AG recommends $69,460 be removed from the revenue requirement because IAWC initially stated that this is the amount that would be saved by discontinuing the study in 2017. AG Ex. 2.0 at 16-17; AG Ex. 4.0 at 1-2. IAWC states that since these are deferred expenses, they would not be recoverable in the current rate case. The Commission agrees that no adjustment is needed to remove an amount that is not reflected in the test year. The Commission declines to make the AG's proposed adjustment.

C. Recommended Operating Revenues and Expenses

Upon giving effect to the determinations above, the Commission finds that the operating statements for IAWC's respective districts are hereby approved as shown in the schedules contained in the Appendices to this Order.

IV. CAPITAL STRUCTURE AND RATE OF RETURN

A. Resolved Issues

1. Capital Structure

The parties agree that the following average test year capital structure is reasonable for setting rates in this proceeding:

CAPITAL COMPONENT	BALANCE	WEIGHT
Short-term Debt	$17,060,924	1.90%
Long-term Debt	$433,176,118	48.30%
Common Equity	$446,559,694	49.80%
Total	$896,796,736	100.00%

Staff Ex. 12.0 at 2, Sched. 12.01; IAWC Ex. 6.00SR at 2; IAWC Ex. 6.01SR; IAWC-IIWC/FEA/CUB Stip. Cross Ex. 1.00 at 4; AG Ex. 3.0 at 3; AG Ex. 3.1 at Sched. A-3. The Commission finds this test year capital structure is appropriate for the purposes of this proceeding and it is hereby approved.

2. Cost of Debt

The parties agree that 0.74% and 5.34% are reasonable average costs of short-term debt and long-term debt, respectively, for IAWC in the test year. IAWC Ex. 6.00R at 3-6, 7-8; IAWC Ex. 6.01R; Staff Ex. 12.0 at 3-4, Sched. 12.01; IAWC-IIWC/FEA/CUB Stip. Cross Ex. 1.00 at 4; AG Ex. 3.1 at Sched. A-3. The Commission finds these test year costs of debt are reasonable and they are hereby accepted.

B. Contested Issues

1. Cost of Common Equity

a. IAWC's Position

***50** IAWC proposes a return on equity ("ROE") of 10.75%. The Company notes that Staff proposes an ROE of 8.12% and a downward adjustment of eight basis points if Rider VBA is adopted. IIWC/FEA/CUB propose an ROE of 9.00%.

The Company asserts that the differences in the recommended ROEs sponsored by the parties in this case are considerable and significant. It states that although the IIWC/FEA/CUB recommendation is low, Staff's recommendation is unprecedented and if adopted, it would cause alarm in the investment community. IAWC Ex. 10.00R at 6. The Company alleges that the Commission has not imposed an ROE as low as Staff proposes in the more than 40 year history that it has been keeping track of ROEs and publishing them. *Id.* at 2-3; IAWC Ex. 10.04R.

IAWC adds that Staff's ROE recommendation is well below the recently-authorized ROEs for other utilities in the country as well as the ROEs for the water companies used in the Company's ROE analyses and the Company's affiliates. IAWC Ex. 10.00R at 3-4, 5. IAWC also contends that the companies in Staff's water sample, which as described below, includes all water utilities within Standard & Poor's ("S&P") Utility Compustat II that have publicly traded stock, have authorized returns averaging 9.65%. IAWC Ex. 10.00R at 4. Moreover, the Company asserts that it already has the lowest authorized ROE of any utility in the American Water system which is problematic because the subsidiaries with competitive rates of return are much more likely to attract the capital necessary to address aging water infrastructure in a more pro-active, accelerated fashion. IAWC Ex. 1.00R at 7; *see also* IAWC Ex. 3.00R at 2-10.

The Company urges the Commission to reject the ROEs recommended by Staff and IIWC/FEA/CUB. It is the Company's position that its witness Mr. Moul's recommended ROE of 10.75% is the most reasonable and should be adopted. IAWC explains that Mr. Moul's cost of equity recommendation is based on analyses using the discounted cash flow ("DCF") model and the capital asset pricing model ("CAPM") and that the risk premium and comparable earnings models were used as a check on reasonableness.

The Company notes that it does not have market-traded common stock, so a proxy group is utilized to conduct the parties' common equity analyses. The proxy group is composed of publicly traded companies comparable, but not identical in risk, to IAWC. IAWC Ex. 10.00 (Rev.) at 3. IAWC witness Moul developed his estimate of the Company's cost of capital using a proxy group of nine water companies ("Water Group"), all of which are contained in the Value Line Investment Survey ("Value Line"); have stock that is publicly traded; and are not currently the target of an announced merger or acquisition. *Id.*

DCF Analysis

The Company states that Mr. Moul used the constant DCF model in his analysis of the cost of equity. IAWC Ex. 10.00 (Rev.) at 21-32. He testified that he generally disfavors a multi-stage or non-constant DCF model because there is no recognized source for analysts' long-term growth expectations. IAWC Ex. 10.00R at 8. He also testified that it is not widely used in regulatory proceedings. *Id.* IAWC states that the underlying theory of the DCF model is that an investment in a utility's stock is worth the present value of future dividends, discounted at a rate commensurate with the risk of the investment. The inputs of this model are current stock price, expected dividend and expected growth rate. IAWC Ex. 10.00 (Rev.) at 17-18. *See also* IIWC/FEA/CUB Ex. 1, App. B at 22-23.

***51** IAWC explains that Mr. Moul's DCF analysis is based on five-year forecasts of earnings growth for each company in his sample. IAWC Ex. 10.00 (Rev.) at 24. The Company asserts that a leverage adjustment to the DCF results was necessary in order to account for the fact that the Company has more debt in its capital structure than the companies in the Water Group, and is therefore subject to more risk. *Id.* at 27-29.

CAPM Analysis

IAWC states that Mr. Moul also used the CAPM in his analysis of the cost of equity. The Company explains that the theory behind the CAPM is that an investor's return equals a risk free rate, plus an associated risk premium. Staff Ex. 5.0 at 15-16. IAWC further explains that the required inputs for this model are an estimate of the 30-year Treasury risk-free rate, beta (a measurement of the systemic risk associated with a stock), and a market risk premium. *Id.; see also* IAWC Ex. 10.00 (Rev.) at 37. Like the DCF, IAWC states that the CAPM is sensitive to the variables used, especially the risk-free rate and market risk premium.

The Company asserts that Mr. Moul chose a forecasted interest rate for 10-year Treasury notes as his proxy for the long-term risk-free rate of return in his CAPM because he believes it is more indicative of “the universal consensus” that interest rates will increase in the future. IAWC 10.00R at 11-13. IAWC explains that Mr. Moul uses Value Line to calculate his beta.

IAWC explains that Mr. Moul applied a leverage and size adjustment to its CAPM results. The Company argues that a size adjustment is warranted because IAWC is smaller than the other companies in the Water Group and therefore it faces an increased level of risk that should be reflected in its ROE. IAWC also argues that Mr. Moul has demonstrated that a leverage adjustment is necessary to properly reflect the fact that the Company carries more financial risk, meaning more debt, than the other companies in the Water Group. IAWC Ex. 10.00 (Rev.) at 28.

Risk Premium and Comparable Earnings Analyses

The Company asserts that while its DCF and CAPM analyses indicate a cost of equity ranging from 9.89% to 10.93%, with an average of 10.41%, additional analyses using the risk premium and comparable earnings models suggest an ROE toward the higher end of this range. IAWC Ex. 10.00 (Rev.) at 2, 4-5, 46. Mr. Moul testified that his recommendation of 10.75% is validated by his risk premium analysis showing a required return of 11.25% and his comparable earnings analysis suggesting a return as high as 13.05%. *See* IAWC Ex. 10.00 at 32, 46.

Response to the Parties' Criticism of IAWC's Common Equity Analysis

IAWC observes that Staff, IIWC/FEA/CUB, the AG, and the Municipalities argue that the Company's ROE estimate is inflated because it includes size and leverage adjustments as well as the risk premium and comparable earnings approaches. IAWC asserts that this argument is not persuasive and it should be rejected.

***52** IAWC notes that these parties state that the Commission has consistently rejected most of these adjustments in prior proceedings. The Company argues that these orders, like all other Commission orders, are not binding on the Commission's determination in this proceeding. *Citizens Util. Bd.*, 166 Ill.2d 111, 132. Further, IAWC notes that the

Commission included model results that reflected size and leverage adjustments in its calculation of ROE in two recent cases. *See Aqua Ill., Inc.*, Docket No. 14-0419, Order at 46 (March 25, 2015); Docket Nos. 12-0511/12-0512 (Consol.), Order at 208.

Additionally, the Company asserts that IAWC witness Moul established that the size and leverage adjustments are necessary. The Company states that Mr. Moul testified that a leverage adjustment needed to be added in the Company's DCF analysis because it has more debt in its capital structure than the companies in the Water Group and therefore it is subject to more risk. IAWC Ex. 10.00 (Rev.) at 27-29. Moreover, Mr. Moul testified that a size adjustment is warranted because IAWC is smaller than the other companies in the Water Group and therefore it faces an increased level of risk that should be reflected in its ROE.

Further, the Company argues that its risk premium and comparable earnings analyses provide extrinsic evidence to support the reasonableness of its proposal. The Company asserts, however, that Staff and IIWC/FEA/CUB cannot point to any extrinsic evidence to support their proposals.

Criticism of Staff's and IIWC/FEA/CUB's Common Equity Analyses

IAWC states that the ROEs recommended by Staff and IIWC/FEA/CUB are low primarily due to their low DCF results. The Company asserts that this is particularly true for Staff. These DCF results, in IAWC's view, are depressing the cost of equity estimates of these parties' to uncharted depths. It argues that the current low interest rate environment does not adequately explain these DCF results. Instead, the Company maintains that the fact that the ROEs recommended by these parties exceeds the highest ROE indicated by their DCF results shows that the DCF understates investor requirements. IAWC explains that the record shows that the ROE estimates by means other than the DCF consistently produce greater returns which indicates that the DCF generally understates the ROE estimates of the witnesses' in this proceeding, especially Staff's. Staff Ex. 5.0 at 14, 26; IIWC/FEA/CUB Ex. 1.0, App. B at 36, 44.

IAWC asserts that although the DCF and CAPM analyses should not be expected to predict the exact same cost of equity, the significant differences between the results derived from these two models in this case should raise serious questions. IAWC argues that ignoring this disparity by simply averaging the results produces a figure that is less likely to represent investor expectations and calculating an average with a below-average figure necessarily yields a below-average "average."

***53** While the Company challenges Staff's and IIWC/FEA/CUB's DCF results, it specifically addresses several flaws in Staff's analyses. First, IAWC points out that Staff decided to use a non-constant or multi-stage growth DCF model because the constant growth DCF typically relies on forecasts of dividend growth for the proxy companies and Staff surmised that the analysts' growth rates of 6.7% to 7.6% are unreasonably high and would result in calculations that overstate ROE if used in a constant growth DCF. Staff Ex. 5.0 at 7-8; Staff Ex. 13.0 at 13. IAWC argues that if Staff had actually performed a constant growth calculation with these growth rates, there would be a basis for comparison of the two methods for the Commission's consideration. The Company also states that it is notable that Staff characterizes the results of a study it did not perform as overstating ROE, but never questions whether the study it performed understates ROE.

Second, the Company asserts that the principal flaw in Staff's DCF analysis is its reliance on a forecasted gross domestic product ("GDP") growth rate of 4.2%. The Company states that Staff's claim that growth rates in excess of projected GDP growth should not be used in DCF calculations is not supported by market data. Staff Ex. 5.0 at 7. It is the Company's position that in a stable business such as public utilities, analysts' forecasts can be used directly in the DCF model without injecting GDP growth. IAWC Ex. 10.00R at 30. IAWC takes issue with Staff's argument that an assumption that utilities could experience dividend growth in excess of GDP means that utilities would eventually overtake the entire U.S. economy. IAWC witness Moul explained that such a claim only holds true if one runs the calculations to infinity. *Id.* at 9. The DCF model mathematically assumes an infinite stream of earnings, but in reality, no financial instrument pays an income stream forever, and IAWC's rates are not going to be in effect forever and the utility sector is only one segment of the economy. *Id.* Therefore, IAWC states that there is no realistic scenario of the water industry, or IAWC in particular, overtaking the entire U.S. economy, regardless of what growth rate is used in a DCF analysis.

Additionally, IAWC notes that Staff asserts that its growth rate is more reasonable because water utilities will experience "below average" growth. Staff Ex. 5.0 at 9. The Company maintains that this assertion is contrary to published analysts' growth rates as well as evidence that the looming need to replace aging infrastructure will drive growth at a faster rate than GDP. IAWC Ex. 10.00R at 10-11.

Third, the Company maintains that the essential flaw inherent in Staff's CAPM analysis is that Staff witness Kight-Garlisch used a Treasury bond yield, which is a spot yield on a single day, instead of looking at available market data for trends in Treasury yields. IAWC Ex. 10.00R at 12. IAWC argues that Staff's CAPM result is understated because it does not reflect the expected increase in interest rates that is indicated in all of the recognized forecasts. Additionally, IAWC contends that it is not impossible to predict the impact of an increase in interest rates as Staff suggests. *Id.* at 13. IAWC points out that Mr. Moul's rebuttal testimony includes a list of five sources that have done so.

FERC Order 531

***54** IAWC urges the Commission to consider the Federal Energy Regulatory Commission's ("FERC") new approach for establishing DCF-based equity returns for utilities under its jurisdiction. *Mass. Att'y Gen. v. Bangor Hydro-Elec. Co.,* 147 FERC 61, 234 (June 19, 2014) ("FERC Order 531") at ¶ 158. The Company states that FERC recently re-evaluated its approach due to the same anomalies in DCF results that the Company highlights. FERC recognized in that order that an ROE based on a "mechanical application" of the DCF "could undermine the ability of the [utilities] to attract capital for new investment" and impose a ""competitive disadvantage" relative to other utilities. *Id.* at ¶ 150. IAWC states that FERC responded to this concern by changing its DCF method to reflect the realities of anomalous markets and bring the results in line with other models. It is the Company's position that FERC's conclusions deserve attention since it is an institution of considerable technical skill and prestige.

IAWC states that both Staff and FERC use the non-constant or multi-stage DCF model (with FERC using two growth stages and Staff using three), but the disparity in results is explainable by the assumed rates of growth and their weighting. IAWC explains that, like the FERC analysis, Staff uses analysts' five-year forecasts for initial stage growth and GDP for final stage growth. Staff Ex. 5.0 at 7-9. However, Staff adds an intermediate growth stage represented by the average of the first and third stage growth rates, and gives each of the three stages equal weighting. *Id.* IAWC further explains that FERC gives the short-term forecast a two-thirds weighting and it gives the long-term forecast a one-third weighting." *Id.* at ¶ 17. IAWC claims that FERC's approach of weighting short-term projections more heavily than long term projections is consistent with the growth rate evidence produced in this proceeding.

According to IAWC, if Staff's variables for growth rates are plugged into the FERC two-stage DCF model, the implied investor required return is 10.51%, which the Company argues fits comfortably within the range of results indicated by IAWC witness Moul. IAWC posits that the Commission is entitled to give this information the weight it believes it deserves.

The Company also asserts that although its DCF model estimates the cost of equity using the single-stage or constant growth rate and includes a leverage adjustment unlike the FERC approach, its DCF results are the only results within the range of the DCF estimate that would be achieved under the FERC approach. IAWC states that the similarity of results confirms that both approaches represent different methods of arriving at similar results for the investor-required

ROE. The Company also notes that the average of its DCF and CAPM results are remarkably close to what it believes the ROE would be if this issue were before FERC.

***55** IAWC argues that rather than simply take the DCF-implied returns at face value, the Commission should take into account the evidence regarding low interest rates, how those interest rates depressed the ROE midpoint, and how interest rates will rise in the near-term. *See* FERC Order 531 at ¶ 130. The Company asserts that the Commission has broad discretion to consider the DCF studies produced in this case and decide for itself how the results should factor into its decision. *People ex. rel. Madigan v. Ill. Commerce Comm'n,* 2015 IL 116005 at ¶ 23, *citing City of Chicago v. Ill. Commerce Comm'n*, 281 Ill. App. 3d 617, 622, 666 N.E.2d 1212 (1st Dist. 1996). Therefore, the Commission may decide to address the phenomenon by adopting the FERC DCF approach, or it may consider other options such as disregarding the DCF studies performed in this case, or giving the CAPM studies more weight than the DCF studies.

Rider VBA Adjustment

IAWC insists that Staff's recommendation that the Company's ROE should be reduced by eight basis points if Rider VBA is approved is baseless and it should be rejected. *See* Staff Ex. 13.0 at 3. The Company understands that Staff claims Rider VBA would reduce volatility in the Company's cash flows and improve its credit rating, thereby decreasing risk and lowering investors' required ROE. Staff Ex. 5.0 at 35, 37. However, IAWC states that this argument ignores the fact that the estimate of the Company's cost of equity is derived from market information on the cost of common equity for other comparable water utilities. IAWC Ex. 10.00R at 19. Moreover, since it has become increasingly common for utility companies in the water, electric, and natural gas industries to employ alternative rate design and ratemaking mechanisms, the approval of trackers, riders, adjustment clauses, forecast test years, and other mechanisms by regulatory commissions is widespread in the utility business and already largely embedded in financial data. *Id.* IAWC argues that therefore it would be inappropriate and result in double counting to include a further adjustment to the extent that the market-derived cost of common equity for other utility companies already incorporates the impacts of these or similar mechanisms.

IAWC notes that five of the nine companies in the Water Group utilize alternative ratemaking mechanisms. *Id.* at 20; *see also* IAWC Ex. 10.02, Sched. 3 at 2. Thus, IAWC states, the existence, approval, and impact of these alternative ratemaking mechanisms is embedded in the data the parties used to develop their ROE analyses, including the stock prices, bond ratings, and business risk scores. IAWC Ex. 10.00R at 21. As a result, the Company maintains, the existence, approval, and impact of the alternative ratemaking mechanisms is embedded in the results of those analyses.

***56** Additionally, IAWC states that its position is well-supported by empirical studies. The Company points to a couple of studies recently published by the Brattle Group which find that there is no statistically significant evidence of a decrease in the cost of capital following adoption of a decoupling mechanism such as Rider VBA. *Id.* at 21-22; IAWC Ex. 10.07R.

In conclusion, IAWC argues that it has provided American Water's customers in Illinois with exceptional service but in order to continue to provide such exceptional service and efficient operations, it must have sufficient funding. The Company asserts that the evidence shows that a range of 9.89% to 10.93% is reasonable, and that qualitative factors such as management performance justify an authorized ROE above the midpoint of this range. Accordingly, IAWC contends that the Commission should approve the Company's proposed ROE of 10.75%.

b. Staff's Position

Staff recommends an ROE for the Company of 8.12%. Staff also suggests a downward adjustment of eight basis points if the Company's proposed Rider VBA is approved by the Commission.

Staff argues that the disparity between its recommended ROE and the Company's proposed ROE stems largely from the Company's inclusion of additional adjustments based on size and leverage. Staff asserts that these adjustments have been repeatedly rejected by the Commission and are not appropriate in this instance. Further, they would result in an ROE recommendation that is out of line with required returns for utilities in general and water utilities specifically.

Staff avers that when the Company's results are corrected to remove these adjustments, the resulting average of the Company's unadjusted ROE analyses is 8.84%, 191 basis points below the 10.75% ROE the Company recommends. Thus, Staff states the recommendations offered by Staff and IAWC are similar after these adjustments are properly removed.

Staff explains that its ROE recommendation is based on the results of its witness Kight-Garlisch's DCF and CAPM analyses. Ms. Kight-Garlisch utilized two proxy groups. The first is a water sample consisting of all S&P utilities that have publicly traded stock and data necessary for analysis. Staff Ex. 5.0 at 3. This water sample consists of six companies, all of which are included in the Company's Water Group. Staff states that Ms. Kight-Garlisch also developed a larger utility sample because she believes smaller samples are prone to increased measurement error. This sample consists of the nine electric and water utilities closest in risk to IAWC based on a comparable risk analysis. *Id.* at 5.

DCF Analysis

Staff indicates that Ms. Kight-Garlisch used a non-constant or multi-stage growth DCF model with three stages of dividend growth. Ms. Kight-Garlisch rejected the constant growth DCF model because she believes it would have required use of unreasonably high growth rates that would be assumed to apply into perpetuity. Staff Ex. 5.0 at 7.

***57** Staff explains that for the first stage, which lasts five years, Ms. Kight-Garlisch used three to five year earnings growth expectations estimated by financial analysts. Staff Ex. 5.0 at 10; Sched. 5.02. In the five-year transitional stage, the growth rate applied was the average of the growth rate for the first and third stages. The long-term growth rate for the third stage, which Staff states begins at the end of the tenth year, was calculated, in part, using the average of the Energy Information Administration and IHS Global Insight forecasts of long-term GDP growth. Staff asserts that this number was combined with the estimate of long-term expected inflation to arrive at the long-term growth estimate of 4.2%. Then, an expected stream of dividends was estimated by applying these stages of growth to the current dividend for each company in the two proxy groups. The discount rate that equates the present value of this expected stream of cash flows to the company's current stock price equals the market-required ROE estimate for each company according to Staff. Staff Ex. 5.0 at 9.

Staff states that Ms. Kight-Garlisch's non-constant DCF estimates of the ROE for the Water Sample and Utility Sample are 7.24% and 7.51%, respectively. *Id.* at 14.

CAPM Analysis

Staff states that Ms. Kight-Garlisch considered U.S. Treasury bonds and U.S. Treasury bills as a proxy for the risk-free rate of return in her CAPM analysis. After considering the pluses and minuses of each of these securities, Ms. Kight-Garlisch determined that the U.S. Treasury bond yield of 2.54% is the best proxy for the long-term risk-free growth rate. *Id.* at 19. Staff contends that it is generally accepted that current interest rates are the best predictor of future interest rates.

Staff asserts that Ms. Kight-Garlisch then estimated the rate of return on the market by conducting a DCF analysis on the firms composing the S&P 500 Index ("S&P 500") as of March 30, 2016. *Id.* at 20. Growth rate estimates were obtained primarily from Zacks and secondarily from Reuters. *Id.* Staff explains that firms were eliminated from the analysis if they did not pay a dividend as of March 30, 2016 or for which neither Zacks nor Reuters growth rates were available. *Id.*

The estimated weighted average expected rate of return for the remaining 418 firms, composing 81.25% of the market capitalization of the S&P 500, equaled 12.03%.

According to Staff, there is no one "true" beta for a company, because betas are forward-looking measures of investors' expectations of market risk. *Id.* at 24. Thus, Ms. Kight-Garlisch used multiple approaches to estimate beta in order to mitigate the effects of measurement error. *Id.* at 25. Staff explains that for the beta parameter, Ms. Kight-Garlisch combined adjusted betas from Value Line, Zacks, Reuters, Morningstar and a regression analysis. *See generally, id.* at 20-23. The Water Sample's average Value Line, Zacks, Reuters, Morningstar and regression beta estimates were 0.75, 0.57, 0.58, 0.58 and 0.57 respectively. Since both the Zacks, Reuters, Morningstar and regression beta estimates are calculated using monthly data, unlike Value Line which uses weekly data, Staff notes that Ms. Kight-Garlisch averaged those results to avoid over-weighting that approach. The average was 0.58 which Ms. Kight-Garlisch then averaged with the Value Line estimate to produce a beta for the Water Sample of 0.66. *Id.* at 24.

***58** Staff states that Ms. Kight-Garlisch undertook the same analysis for the Utility Sample. The average of the Zacks, Reuters, Morningstar, and regression beta estimates was 0.57 which Ms. Kight-Garlisch averaged with the Value Line beta to produce a beta for the Utility Sample of 0.67.

Staff points out that by inputting the risk-free rate of return, the estimated market rate of return, and the beta into the CAPM, Ms. Kight-Garlisch calculated a cost of common equity of 8.80% for the Water Sample and 8.90% for the Utility Sample.

Rider VBA Adjustment

Staff recommends a downward adjustment of eight basis points to the Company's ROE if the Commission adopts Rider VBA. Staff Ex. 13.0 at 3. Staff argues that this adjustment should be made because Rider VBA will reduce the risk faced by the Company since it will reduce the volatility in the Company's cash flows by decoupling the recovery of fixed cost from its volume of water sales. Staff Ex. 5.0 at 32.

Response to IAWC's Criticism of Staff's Common Equity Analysis

Staff argues that the Company's comparison of Staff's recommended ROE to other companies' allowed ROEs is not the appropriate benchmark and it only serves to undermine the validity of the Company's ROE analyses. Moreover, Staff states that the arguments advanced by the Company concerning Staff's DCF and CAPM results are unconvincing.

Staff observes that the Company argues that the essential flaw in Staff's CAPM analysis is that Ms. Kight-Garlisch's Treasure bond yield does not reflect the expected increase in interest rates. Staff states that this argument should be rejected for the reasons noted below in Staff's critique of the Company's CAPM results.

Staff further notes that the Company argues that Staff's ROE recommendation is low primarily because of its DCF results. Staff asserts that its ROE recommendation is not based solely on its DCF results but rather it is derived from its DCF and CAPM analyses. Therefore, the Company's focus on Staff's DCF analysis in isolation misconstrues Staff's recommendation. Staff argues that it has presented evidence that shows, that regardless of the analysis, returns have fallen compared to the Company's last rate case. IAWC Ex. 10.00R at 4. Staff points to the fact that the Company's own unadjusted analyses show a recommended ROE below its currently authorized ROE.

Criticism of IAWC's Common Equity Analysis

Staff challenges IAWC's common equity analysis for several reasons, including the Company's use of adjustments based on size and leverage as noted above. Staff argues that the Company's DCF analysis is overstated because it uses unreasonable growth rates. Staff states that the Company's long-term growth rate of 6% is not a reasonable estimate of long-term sustainable growth. Staff argues that while it is a commonly accepted practice to use three to five year growth rates in a constant growth DCF analysis, at least as a starting point, use of that growth rate is appropriate only if it is sustainable for the long term. In this instance, Mr. Moul's growth rate of 6% is 43% above the estimated long-term growth rate of the economy as a whole. Staff notes that Mr. Moul defends his growth rate, stating that "no financial instrument pays an income stream forever, and IAWC's rates are not going to be in effect forever." IAWC Ex. 10.00R at 9. Staff argues that Mr. Moul's assertion may be true, however, it is a necessary assumption in DCF analysis that the growth rate will continue in perpetuity and Mr. Moul's estimate is mathematically impossible to sustain to infinity.

***59** Staff states that Mr. Moul's DCF analysis also incorporates a clearly aberrant growth rate. Staff explains that Mr. Moul's Water Group includes a company that has a forecasted short-term growth rate of 14.00% which is a clear outlier and unsustainable over the long term. IAWC Ex. 10.02R, Sched. 7. Staff notes that Ms. Kight-Garlisch's DCF analysis included this same initial stage outlier, but she also used intermediate and long-term growth estimates for this company that are consistent with expected growth in these stages (9.20% for the intermediate stage and 4.20% for the long-term stage) which decreased the significance of this one company in the proxy group.

Staff argues that the Company's CAPM analysis is also overstated, primarily because its uses a forecasted interest rate, a single source to calculate its beta, and size and leverage adjustments. Staff takes issue with Mr. Moul's use of a forecasted interest rate in his CAPM analysis. Staff does not believe there is evidence to support his assertion that there is a "universal consensus" that interest rates will increase in the future. IAWC 10.00R at 11-13. Thus, Staff disagrees with Mr. Moul's use of the forecasted interest rate for 10-year Treasury notes as his proxy for the long-term risk-free rate of return. Staff argues that Mr. Moul's calculations, which show that his risk-free rate of return estimate decreased from his direct testimony to his rebuttal testimony, demonstrate that his assumption is tenuous. IAWC Ex. 10.02R, Sched. 1. Staff asserts that it is impossible to predict the impact of any increase in interest rates because the economy could grow or slow depending on the size of the increase and how it is perceived. Further, Staff maintains that the best indicator of long-term interest rates is the current interest rate, which Staff has proposed. Staff Ex. 13.00 at 16-18.

Staff contends that Mr. Moul's use of a single source, Value Line, to calculate his beta in his CAPM analysis is also problematic. In Staff's view, the more estimates used, the less possibility that a beta is unduly affected by a random or one-off event. Additionally, Staff questions the accuracy of Value Line's beta because its weekly beta was significantly higher than the four other betas that Ms. Kight-Garlisch used in her CAPM analysis. Staff Ex. 5.0 at 24.

Staff further argues that the leverage and size adjustments included in Mr. Moul's CAPM analysis are inappropriate and unreasonable. Staff notes that Mr. Moul testified that a leverage adjustment is necessary when a firm's capitalization as measured by market value differs from its book value capitalization, because the potential exists for a financial risk difference. IAWC Ex. 10.00 at 27. Staff contends that this assertion does not aid IAWC for numerous reasons. First, the Company does not have a market value since it is not publicly traded. But, assuming for the sake of argument that its market value exceeds book value, the Company offers no evidence that this in turn leads to increased risk that is not already accounted for by the various other components of ROE calculation methods. Second, the change in risk that Mr. Moul addresses is actually the result of fluctuating debt to equity ratios over time. Third, the Company presents no evidence that it faces unusual risk necessitating a leverage adjustment. Fourth, Mr. Moul has presented this adjustment before and the Commission has rejected the exact same adjustment in previous cases. *See N. Shore Gas Co*., Docket Nos. 14-0224/14-0225 (Consol.), Order at 132, 134 (Jan. 21, 2015); Docket Nos. 09-0166/09-0167 (Consol.), Order at 128; Docket Nos. 07-0241/07-0242 (Consol.), Order at 96.

***60** Staff also takes issue with Mr. Moul's claim that a size adjustment is necessary. First, Staff contends that there is no theoretical basis for the adjustment and to the extent there is any correlation between firm size and return, that relationship is likely the result of some other related factors, such as liquidity and information costs, rather than a direct relationship between size and return. Staff Ex. 5.0 at 43. Second, even if one were to accept as a general proposition that smaller companies are riskier than larger companies, IAWC offers no evidence that a size premium should be applied to utilities. *Id.* at 44. Third, since the common equity of IAWC is obtained indirectly from investors through American Water, a much larger organization, neither IAWC nor American Water incur the additional costs allegedly associated with smaller companies. Staff Ex. 13.00 at 21.

IAWC's ROE analysis is also overstated, in Staff's view, because it incorporates the risk premium and comparable earnings approaches. Staff argues that Mr. Moul's equity risk premium estimate contains many flaws. It is derived from historical data, which Staff believes is inappropriate because the S&P 500 is riskier than utilities generally, therefore its investor required rate of return exceeds the cost of common equity for water utilities. Mr. Moul's estimate is based on the average spread between earned returns and interest rates but there is no way, in Staff's opinion, to know whether the earned rate of return is higher or lower than the rate of return investors required at some point in the past. Staff Ex. 5.0 at 48-49. In addition, Staff states that utilizing a forecasted base yield instead of a yield based on current interest rates, inappropriately increases Mr. Moul's risk premium results by 0.79%. Staff Ex. 5.0 at 49.

Staff maintains that IAWC's use of the comparable earnings approach also distorts the Company's ROE analysis. Staff explains that the cost of common equity is the market-driven rate of return demanded by investors. In contrast, comparable earnings analysis is a book-based methodology that incorrectly implies that the earned rate of return on book equity is equivalent to the investor-required market rate of return. Staff Ex. 5.0 at 51. Staff asserts that it should not be used to assess investor expectations because the market price of a common stock reacts to forces in the marketplace while the book value remains constant whether the market goes up or down. *Id.* Staff notes that the Commission has routinely rejected the use of comparable earnings methodology in rate cases for this reason. *See* Docket Nos. 14-0224/14-0225 (Consol.), Order at 134; *Cent. Ill. Light Co.*, Docket Nos. 06-0070/06-0071/06-0072 (Consol.), Order at 141 (Nov. 21, 2006); *Aqua Ill., Inc.*, Docket No. 04-0442, Order at 43-44 (Apr. 20, 2005); Docket No. 03-0403, Order at 41; *Cent. Ill. Pub. Serv. Co*., Docket No. 99-0121, Order at 68 (Aug. 25, 1999); *Ill. Bell Tel. Co.*, Docket Nos. 92-0448/93-0239 (Consol.), Order at 173 (Oct. 11, 1994); *Ill. Bell Tel. Co.*, Docket No. 89-0033, Order on Remand at 15 (Nov. 4, 1991).

FERC Order 531

***61** Staff argues that it is highly questionable if FERC Order 531 is relevant. Staff states that while the Company suggests FERC Order 531 must be considered because FERC "is an institution of considerable technical skill and prestige," the Company makes no effort to explain why the "technical skill" of a federal commission charged with regulating interstate electric transmission and power markets has any import in determining the ROE for an Illinois water company. Staff also argues that the Commission should consider FERC Order 531 in its entirety if it determines that it is relevant in this proceeding. Additionally, Staff asserts that the order undermines the Company's ROE recommendation in several ways.

First, FERC Order 531 establishes that, once a range of reasonable ROEs is established for companies in the proxy group, the ROE for the subject company must fall within that range. Staff notes that Mr. Moul did not present ROEs for the individual companies in his proxy group, nor did he establish a DCF range for the companies in his proxy group, both of which are required by the FERC methodology.

Second, the FERC methodology, like Staff's analysis, considers both short and long-term growth rates while the Company considers only a short-term, five-year growth rate. IAWC Ex. 10.00 (Rev.) at 24. Staff points out that FERC Order 531 states that: "To the extent a high DCF estimate is based on [a] five-year projection, that result is inconsistent with the theory underlying the constant growth DCF model, which requires an estimate of dividend growth extending into the indefinite future." FERC Order 531 at ¶ 37. FERC also noted that five-year growth projections like the one utilized by Mr. Moul are "limited to too brief a time period to meet the requirements of the DCF model." FERC Order

531 at ¶ 19 (internal citations omitted). Staff also notes that FERC addresses the limitations inherent in speculating about long-term investment by crafting a method to weight long-term growth but Mr. Moul "addresses" it by simply ignoring long-term growth. Further, the FERC analysis uses a two-stage non-constant growth rate and the Company's witness specifically rejected anything other than a constant growth rate DCF analysis.

Third, FERC Order 531 states that additional methodologies such as CAPM or a risk premium analysis are useful for determining where in the DCF range the final ROE should fall but the ROE must still be within the DCF range. Staff asserts that this is contrary to Mr. Moul's approach of determining an ROE using DCF and CAPM analyses and then adding on adjustments which he attempts to justify through additional methodologies.

Additionally, Staff notes that FERC Order 531 establishes the long-term growth rate as the forecasted GDP of the economy as a whole, which is 4.2%. Mr. Moul, however, testified that he disagrees with the use of the forecasted GDP as an appropriate indicator of long-term growth and he used a future growth rate of 6% in his analysis. IAWC 10.00R at 10. Staff asserts that Mr. Moul's DCF results would therefore be lower under the FERC's methodology because the long-term growth rate would be based on the forecasted GDP of 4.2% instead of the Company's rate of 6%.

***62** Finally, Staff notes that the Company erroneously asserts that Staff's DCF results would be higher "[i]f Staff's variables for growth rates are plugged into the FERC two-stage DCF model." Staff states that this assertion completely ignores the fact that the FERC Order adopts a new methodology to calculate growth rates for use in a DCF model. *Id.* at 13. Therefore, an analysis using FERC's methodology would not involve the use of any of the party's growth rate numbers.

c. AG's Position

The AG asserts that it supports Staff's ROE recommendation and strongly opposes IAWC's proposed ROE which it states is an outlier that must be rejected. The AG contends that IAWC witness Moul's recommended ROE is grossly inflated because it relies on several methodologies that have the singular effect of driving the proposed ROE higher. The AG notes that Staff witness Kight-Garlisch testified that these tactics have been repeatedly and consistently rejected by the Commission, yet Mr. Moul failed to provide any response or offer an explanation as to why the Commission should deviate from its past decisions rejecting these ROE-inflating methods. Staff Ex. 5.0 at 42, 46, 50, 52. The AG points out that Ms. Kight-Garlisch also testified that when the effects of two of these tactics are removed, Mr. Moul's proposed ROE is reduced to a range of 8.89% to 9.00%, which is much closer to Ms. Kight-Garlisch's proposal, and at the high end, identical to IIWC/FEA/CUB witness Gorman's recommendation. Staff Ex 5.0 at 40; IIWC/FEA/CUB Ex. 1.0 at 4.

The AG notes that the size adjustment that Mr. Moul added to his CAPM results has been rejected in numerous cases, including in IAWC's penultimate rate case, Docket No. 09-0319. IAWC Ex. 10.00 (Rev.) at 41-42; *see* Docket No. 09-0319, Order at 113; Docket Nos. 11-0280/11-0281 (Consol.), Order at 123; *Aqua Ill., Inc.*, Docket No. 110436, Order at 38 (Feb. 16, 2012).

Next, Mr. Moul used a leverage adjustment in his DCF analysis, but the AG notes that the Commission has also repeatedly declined to adopt leverage adjustments in previous cases, including at least three in which Mr. Moul proposed this adjustment. The AG points to the Commission's decision in Docket Nos. 14-0224/14-0225 (Consol.), in which the Commission stated that Mr. Moul's CAPM result was inappropriately inflated because he "appl[ied] a Commission rejected leverage adjustment technique to the beta measurement." Docket Nos. 14-0224/14-0225 (Consol.), Order at 133. The AG also notes that the Commission rejected Mr. Moul's leverage adjustment in Docket Nos. 09-0166/09-0167 (Consol.) and Docket Nos. 07-0241/07-0242 (Consol.). Docket Nos. 09-0166/09-0167 (Consol.), Order at 127; Docket Nos. 07-0241/07-0242 (Consol.), Order at 96.

***63** The AG explains that Mr. Moul also boosted his ROE by employing a risk premium model which is another tactic that the Commission has repeatedly found to be improper. IAWC Ex. 10.00 (Rev.) at 32-37. The AG states that on five separate occasions, Mr. Moul recommended that the Commission use this model as part of his ROE analysis, but in each case, the Commission declined to do so. *See* Docket Nos. 14-0224/14-0225 (Consol.), Order at 134; Docket Nos. 12-0511/12-0512 (Consol.), Order at 208; Docket Nos. 11-0280/11-0281 (Consol.), Order at 139; Docket Nos. 09-0166/09-0167 (Consol.), Order at 139; and Docket Nos. 07-0241/07-0242 (Consol.), Order at 93.

The AG also criticizes Mr. Moul's use of a comparable earnings analysis to augment his recommended ROE. IAWC Ex. 10.00 (Rev) at 42-46. The AG explains that like Mr. Moul's other adjustments and methodologies, the Commission has on several occasions refused to include a comparable earnings analysis as part of its ROE determination. *See* Docket Nos. 14-0224/14-0225 (Consol.), Order at 134; Docket Nos. 06-0700/06-0071/06-0072 (Consol.), Order at 141-142; Docket No. 04-0442, Order at 43-44; and Docket No. 03-0403, Order at 41.

In addition to the various adjustments and alternative measurement methods Mr. Moul employed, the AG argues that Mr. Moul dedicated significant portions of his testimony to comparisons of Staff's and IIWC/FEA/CUB's ROE recommendations to ROEs approved by other public utility commissions around the country. IAWC Ex. 10.00R at 3-6; IAWC Ex. 10.00SR at 3-4, 6-7. The AG asserts that the Commission has consistently rejected this tactic also. *See Commonwealth Edison Co.*, Docket No. 05-0597, Order at 153 (June 6, 2006); Docket Nos. 07-0241/07-0242 (Consol.), Order at 90-91.

Finally, the AG notes that Mr. Moul testified that the return generated by his various analyses was 10.70% and he rounded up the 10.70% "to the nearest one-quarter percentage point, or 10.75%." IAWC Ex. 10.00R at 30. Mr. Moul did not provide any other reason or explanation for adding five basis points to his recommended return. The AG asserts that the ease with which he increased his result raises serious questions regarding the credibility of Mr. Moul's testimony and his recommendations.

For these reasons, the AG concludes that the Commission should reject IAWC's proposed ROE and adopt Staff's recommended ROE instead.

d. IIWC/FEA/CUB's Position

***64** IIWC/FEA/CUB witness Gorman recommended an ROE of 9.00% for IAWC. IIWC/FEA/CUB argue that IAWC's proposed ROE of 10.75% is excessive and the Company's analyses are severely biased, or reflect inappropriate data.

IIWC/FEA/CUB state that Mr. Gorman's cost of equity recommendation is based on analyses of several versions of the DCF model and the CAPM. IIWC/FEA/CUB state that Mr. Gorman relied on two proxy groups to estimate IAWC's cost of capital: the water utility proxy group developed by Mr. Moul and a gas utility proxy group. IIWC/FEA/CUB claim that these two proxy groups together provide the most reasonable estimate of IAWC's investment risk for several reasons. IIWC/FEA/CUB Ex. 1.0, App. B at 20. First, a gas proxy group's securities are more widely followed by securities analysts than are water utility stocks, and therefore the estimated cost of equity from a gas proxy group provides a more robust estimate of IAWC's current market cost of equity. *Id.* Second, the asset capitalization and operations of gas utilities and water utilities are very similar. *Id.* Third, the two groups are reasonably comparable to IAWC in investment risk. *Id.* at 21.

DCF Analysis

IIWC/FEA/CUB assert that Mr. Gorman used the following versions of the DCF model to develop his ROE recommendation: (i) the constant growth DCF model using analysts' growth rate data, (ii) a sustainable growth DCF model, and (iii) the non-constant or multi-stage growth DCF model. IIWC/FEA/CUB Ex. 1.0, App. B at 19.

IIWC/FEA/CUB explain that Mr. Gorman included a quarterly compounding adjustment to his DCF return estimate because it is the Commission's standard practice to include this quarterly compounding return in DCF estimates. They caution, however, that replicating reinvestment of quarterly dividends over a year can overstate a fair ROE for setting rates. IIWC/FEA/CUB Ex. 1.0, App. B at 23.

In his constant growth DCF analysis, IIWC/FEA/CUB assert that Mr. Gorman used the average of the weekly high and low stock prices of the proxy groups over a 13-week period ended April 29, 2016. For dividends, IIWC/FEA/CUB state that Mr. Gorman used the most recently paid quarterly dividends from Value Line of March 4, 2016. *Id.* at 24. IIWC/FEA/CUB point out that Mr. Gorman relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for the investor consensus dividend growth rate expectations. He then used the average of three sources of analysts' growth rate estimates: Zacks, Yahoo! Finance, and Reuters. *Id.* at 25. IIWC/FEA/CUB state that the average and median constant growth DCF returns for the water utility proxy group are 9.12% and 8.00%, respectively. The average and median constant growth DCF returns for the gas utility proxy group are 9.12% and 9.27%, respectively. *Id.*

***65** In his sustainable growth rate DCF analysis, IIWC/FEA/CUB state that Mr. Gorman based his estimate of the long-term sustainable growth rate on the proxy group companies' current market to book ratios and on Value Line's three to five year projections of earnings, dividends, earned returns on book equity, and stock issuances for each company. *Id.* at 28. IIWC/FEA/CUB state that Mr. Gorman calculated a sustainable growth DCF analysis for the water utility proxy group to produce average and median DCF results of 8.05% and 8.30%, respectively. The average and median DCF results for the gas utility proxy group are 9.48% and 9.46%, respectively.

In his multi-stage growth DCF analysis, IIWC/FEA/CUB state that for the shortterm growth period, Mr. Gorman relied on the consensus analysts' growth projections described above in relationship to his constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor, which reflects the difference between the analysts' growth rates and the GDP growth rate. *Id.* at 30. For the long-term growth period, IIWC/FEA/CUB explain that, Mr. Gorman assumed each company's growth would converge to the maximum sustainable growth rate for a utility company as proxied by the consensus analysts' projected growth for the U.S. GDP of 4.2%. *Id.* at 30-32.

IIWC/FEA/CUB observe that Mr. Gorman developed his long-term sustainable growth rate based on the latest issue of Blue Chip Economic Indicators, which published a consensus economists GDP growth rate outlook of 4.2% over the next 5 and 10 years, respectively. *See id.* at 27, *citing* Blue Chip Economic Indicators, March 10, 2016 at 14. Mr. Gorman used the midpoint of the consensus economists' projected 5 and 10 year GDP consensus growth rate of 4.2% as an estimate of long-term sustainable growth. *Id.* at 32. IIWC/FEA/CUB note that Mr. Gorman also used the same 13-week stock price, dividend, and growth rates that he used for his constant growth DCF analysis. *See Id.* at 35. Using this model, the average and median multi-stage growth DCF returns on equity are 7.09% and 6.82%, respectively, for the water proxy group. The average and median returns are 7.64% and 7.53% for the gas proxy group. *Id.* at 35. IIWC/FEA/CUB note that Mr. Gorman testified that he included this additional model in his analyses to reflect the outlook of changing growth expectations.

IIWC/FEA/CUB state that the DCF studies performed by Mr. Gorman support an ROE of 8.80%, which is the midpoint of his DCF range of 8.3% to 9.3%.

CAPM Analysis

As noted above, IIWC/FEA/CUB witness Gorman also used the CAPM to estimate the Company's required ROE.

IIWC/FEA/CUB note that the Blue Chip Economic Indicators' projected 30 year Treasury bond yield of 3.50% was used for Mr. Gorman's CAPM analysis, because longterm Treasury bonds are considered to have negligible credit risk. *Id.* at 38. Mr. Gorman used the beta values for the water and gas utility proxy groups' average Value Line beta estimates of 0.71 and 0.79, respectively. *See* IIWC/FEA/CUB Ex. 1.0, App. B, Ex. 1.10.

***66** IIWC/FEA/CUB point out that Mr. Gorman developed two versions of a prospective market risk premium estimate because they believe the Commission prefers prospective market risk premiums. IIWC/FEA/CUB Ex. 1.0, App. B at 42. Mr. Gorman offered a risk premium method of estimating a prospective return on the market. This methodology produced a return on the market of 11.4%, which was reduced by Mr. Gorman's risk-free rate estimate of 3.5%, resulting in a prospective market risk premium estimate of 7.9%. *Id.* Mr. Gorman's second prospective market risk premium estimate was based on a DCF return on the market. *Id.* at 43. This methodology produced a DCF return on the market of 10.53%, which was reduced by Mr. Gorman's risk-free rate estimate of 3.5%, resulting in a market risk premium of 7.0%. *Id.* at 43-44.

IIWC/FEA/CUB conclude that Mr. Gorman's CAPM study estimated an ROE for IAWC in the range of 8.50% to 9.80% with a midpoint of 9.15%, which Mr. Gorman rounded to 9.2% for purposes of this proceeding. *Id.* at 44. Mr. Gorman's estimate reflects a risk-free rate of 3.5%, a market risk premium in the range of 7.0% to 7.9%, and proxy group betas of 0.71 to 0.79 for his water and gas proxy groups, respectively. *Id.* at 44.

Criticism of IAWC's Common Equity Analysis

IIWC/FEA/CUB state that IAWC's DCF return estimate is overstated because IAWC witness Moul unjustifiably added a leverage adjustment to the results of his DCF study. IIWC/FEA/CUB argue that Mr. Moul's leverage adjustment is nothing but a marketto-book ratio adjustment and it should be rejected. *Id.* at 51. IIWC/FEA/CUB opine that it is not just and reasonable because it is designed to inflate market prices, rather than provide a fair rate of return on investment in utility plant and equipment. *Id.* at 51. Moreover, the Commission has rejected earlier versions of Mr. Moul's leverage adjustment in previous cases. IIWC/FEA/CUB submit that removing Mr. Moul's leverage adjustment from his recommended DCF return of 9.72% produces a reasonable DCF return for IAWC of 8.78% or 8.8%.

IIWC/FEA/CUB also complain that Mr. Moul's CAPM analysis includes a leverage adjustment to the beta estimate and a size adjustment to his proxy group CAPM return estimate. IIWC/FEA/CUB aver that Mr. Moul's proposed leverage adjustment is unreasonable and should be rejected. They argue that the leverage adjustment to the beta estimate reflects only one element of risk that should be captured in a beta estimate. Further, adjusting the observed market beta as published by Value Line results in a CAPM return estimate that is not consistent with independent market participants' risk assessment and published data for the proxy group companies. *Id.* at 60.

IAWC's size adjustment is without merit and should also be rejected, in IIWC/FEA/CUB's view. They assert that IAWC is not a stand-alone small utility company. Rather, it is a subsidiary of one of the largest publicly traded water utility companies in the U.S. *Id.* at 61. The Company's customers pay for the affiliation with its parent company through increased Service Company fees. IIWC/FEA/CUB Ex. 2.0 (Rev.) at 14. This affiliation with a large water company and the payment of Service Company fees, IIWC/FEA/CUB argue, mitigates IAWC's risk and provides it economies of scale, and support. Further, IIWC/FEA/CUB claim that Mr. Moul's size adjustment does not correctly follow Ibbotson data used to develop his CAPM risk premium. IAWC Ex. 10.00 (Rev.) at 35. Ibbotson recommends CAPM adjustment for company size and also industry risk. However, IIWC/FEA/CUB note that Mr. Moul did not include a CAPM adjustment for industry risk in his analysis. This adjustment, IIWC/FEA/CUB state, would have resulted in a return below the 8.9% produced by the traditional CAPM on the Water Group. IIWC/FEA/CUB Ex. 1.0, App. B at 61-65. IIWC/FEA/CUB note that excluding Mr. Moul's leverage adjustment and small size adjustment from Mr. Moul's CAPM study produces an ROE estimate of 8.9% for IAWC. IAWC Ex. 10.02R at 1 of 12, Sched. 1.

***67** IIWC/FEA/CUB contend that Mr. Moul's use of a risk premium study should also be rejected because its produces overstated estimates. They argue that the Commission has continually rejected the use of this methodology because it is not a reliable methodology for estimating a fair ROE for a utility. They note that IIWC/FEA/CUB witness Gorman concluded that Mr. Moul's estimate of this 6.5% equity risk premium is arbitrary and has not been shown to be an appropriate risk premium for a below-market risk utility investment like IAWC. IIWC/FEA/CUB Ex. 1.0, App. B at 56-57. IIWC/FEA/CUB contend that adjusting the 6.5% market risk premium estimated by Mr. Moul for IAWC's below-market risk would support a risk premium of approximately 4.5% using Mr. Moul's methodology. *Id.* at 58-59. Further, IIWC/FEA/CUB argue that including a more appropriate risk-adjusted risk premium of 4.5%, and a current observable bond yield of 4.1% would produce a more reasonable estimate of a fair ROE for IAWC of 8.6%. *Id.*

IIWC/FEA/CUB also oppose the use of Mr. Moul's comparable earnings analysis in this proceeding. They note that Mr. Gorman explained that Mr. Moul's comparable earnings analysis is fundamentally flawed and unreliable for at least three reasons. First, it does not measure a return investors require in order to assume the investment risk of a company like IAWC. IIWC/FEA/CUB Ex. 1.0, App. B at 66-67. Second, it compares companies that have not been shown to have comparable risk to that of IAWC. *Id.* at 67. Finally, it is tied to non-regulated companies which may have different accounting standards, and earned returns that may not be directly comparable to the earned return for a regulated company. *Id.*

FERC Order 531

IIWC/FEA/CUB believe the Commission should completely disregard the Company's reliance on FERC Order 531 to support a higher DCF result for several reasons. First, since IAWC did not advance its late argument based on this Order until its Initial Brief, it has not been established in the record whether this Order, which concerns electric transmission utilities and not water utilities, is relevant. Second, the parties have not had an opportunity to cross examine IAWC witness Moul regarding the conflict between his preference for a constant growth DCF approach and the two stage DCF approach used in FERC Order 531. Third, the Company's assertions and inferences regarding this Order have no record support since they have not been tested in an evidentiary hearing. Finally, IIWC/FEA/CUB argue that the Company's analysis suffers from many infirmities, including the Company's use of incorrect data.

e. Municipalities' Position

The Municipalities argue that the Commission should reject IAWC's proposed ROE and adopt Staff's ROE recommendation. The Municipalities opine that Staff's recommendation properly includes a downward adjustment of eight basis points if the Commission approves the Company's proposed Rider VBA since the rider reduces the Company's business risk associated with a decrease in sales.

***68** The Municipalities believe IAWC's proposed ROE is faulty for the same reasons asserted by Staff and the AG. They state that Staff witness Kight-Garlisch's testimony clearly demonstrates that the Company's proposal is based on adjustments that the Commission has consistently rejected in past cases and that the Company has presented no valid reasons to support its argument that the Commission should accept these adjustments in this case. Staff Ex. 5.0 at 40.

Additionally, the Municipalities state that in an attempt to gloss over these flaws, IAWC cites FERC Order 531. The Municipalities assert that they agree with Staff that the applicability of a FERC decision regarding electric transmission companies to an Illinois water utility case is questionable. They urge the Commission to rely on its own prior cases and reject IAWC's unsupported 10.75% ROE.

f. Commission Analysis and Conclusion

The Commission observes that estimating the cost of common equity is perhaps one of the most challenging aspects of a rate case proceeding. The Commission has relied primarily on the data derived from financial models that attempt to quantify the cost of attracting capital investment during the time period for which the rates will be in effect. Historically, the Commission has given substantial weight to the results of the DCF and CAPM analyses of the parties' expert witnesses. The Commission has discretion to consider other factors when weighing its decision.

In estimating the cost of common equity, the Commission must consider not only the outputs of the financial models, but whether the authorized ROE satisfies the standards set forth in *Bluefield Water Works & 398 Improvement Co. v. Public Service Commission of West Virginia,* 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944). These decisions establish that a regulatory body such as the Commission must consider whether the authorized return will allow a return that is sufficient to maintain the utility's financial integrity and to attract capital at reasonable terms, while ensuring that customers do not pay an excessive or unreasonable return on those rates. Bluefield, 262 U.S. at 692-93; Hope, 320 U.S. 591 at 603. The Company must be able to provide safe, reliable service at just and reasonable rates. Bluefield, 262 U.S. at 693; Hope, 320 U.S. 591 at 603. The return should be commensurate with returns investors could earn by investing in other companies of comparable risk. Bluefield, 262 U.S. at 692; Hope, 320 U.S. 591 at 603.

IAWC, Staff, and IIWC/FEA/CUB presented witnesses who testified concerning their recommendations for the Company's cost of common equity. While all of the witnesses performed their analyses using the DCF and CAPM analyses, their recommendations differ considerably. IAWC witness Moul proposed an ROE of 10.75%; Staff witness Kight-Garlisch proposed an ROE, if Rider VBA is adopted, of 8.04%; and IIWC/FEA/CUB witness Gorman proposed an ROE of 9.00%. While the Commission believes results derived from the DCF and CAPM analyses should not be expected to produce the exact same cost of equity, there were significant differences between both the methodologies employed and the results derived by the parties in this case. IAWC Initial Brief at 2-3; IAWC Reply Brief at 1-4.

***69** The Company argues that the ROE estimates proposed by Staff and IIWC/FEA/CUB are low in large part because their DCF results are uncharacteristically low which is depressing their overall estimates. IAWC Initial Brief at 12. Additionally, the Company argues that the disparity between the CAPM results and DCF results offered by these parties shows that the DCF analysis understates investor requirements. IAWC Initial Brief at 11-12. However, Staff, IIWC/FEA/CUB, the AG, and the Municipalities argue that the difference is due to the Company's inclusion of additional adjustments and methodologies that have been rejected by the Commission in past proceedings. Staff Ex. 5 at 40; IIWC/FEA/CUB Ex. 1.0, App. B at 50-52; Municipalities Initial Brief at 3-4. See generally AG Initial Brief.

The Commission agrees with the Company that Staff's proposed ROE of 8.04% is anomalous. [3] An authorized rate of return that is not competitive will deter continued investment in the State of Illinois. IAWC Ex. 1.00R at 5; IAWC BOE at 5. A reasonable authorized ROE helps ensure that the Company can attract capital in order to meet the Commission required infrastructure repair and replacement needs of the State. IAWC Ex. 1.00R at 7; see also IAWC Ex. 3.00R at 2-10.

In order to address the abovementioned concerns, the Commission finds that an average of the ROE results recommended by IAWC and IIWC/FEA/CUB, which is 9.87%, should be used to calculate the Company's ROE in this proceeding. The parties have pointed out various flaws in each parties' analyses. However, the Commission believes an average of these results will minimize many of the shortcomings identified by the parties.

The Commission acknowledges that IAWC's DCF and CAPM results contain size and leverage adjustments. IAWC Reply Brief at 15-18; IAWC Ex. 10.00R at 15-18. However, the ROE approved by the Commission in the instant docket is an average of IAWC's and IIWC/FEA/CUB's ROE recommendations and not an endorsement of every input of every aspect of the methodologies performed by these parties. See Docket No. 14-0419 at 44.

***70** The Commission agrees with both Company and Staff that the adoption of Rider VBA will reduce IAWC's operating risk. IAWC Ex. 10.00R at 21; Staff Ex. 5.0 at 2, 32. Staff's recommended adjustment ranges from an 8 to 28 basis point reduction. Staff Ex. 13.0 at 3; Staff Ex. 5.0 at 2, 32. Overall, the record supports a downward adjustment, and the Commission finds it reasonable to reduce the ROE by eight (8) basis points. Accordingly, the Commission deducts eight basis points from the average of IAWC's and IIWC/FEA/CUB's proposed ROEs for a final ROE of 9.79%.

Finally, the Commission will not consider FERC Order 531 in this proceeding. The Commission agrees with Staff, IIWC/FEA/CUB, and the Municipalities that the Company failed to establish that this Order, which concerns electric transmission utilities and not water utilities, is relevant to this proceeding. Moreover, the Commission notes that the Company should have proposed the new methodology that it appears to be advocating in post-hearing briefs earlier in this proceeding to allow the parties an opportunity to develop a full record on this issue.

For the reasons stated above, the Commission concludes that IAWC's cost of common equity is 9.79%. This number reflects an average of IAWC's and IIWC/FEA/CUB's proposed ROEs, which is 9.87%, and deducts eight (8) basis points due to the adoption of Rider VBA for a final ROE of 9.79%. The Commission finds that this ROE is reasonable, supported by the record, and consistent with the governing legal standard. The Commission's analysis in this case is not indicative of how the Commission will review and decide upon ROE in future rate cases, nor shall this decision obligate the Commission to apply the same or similar analysis in future proceedings.

C. Recommended Capital Structure and Rate of Return

Having considered the conclusions above concerning the Company's capital structure and costs of debt and equity, the Commission finds that the Company should be authorized to earn a rate of return of 7.47%. The rate of return incorporates an ROE of 9.79%. The Company's rate of return was derived as follows:

CAPITAL COMPONENT	WEIGHT	COST	WEIGHTED COST
Short-term Debt	1.90%	0.74%	0.01%
Long-term Debt	48.30%	5.34%	2.58%
Common Equity	49.80%	9.79%	4.87%
Total	100.00%		**7.47%**

V. RIDERS

A. Resolved Issues

1. Pension/OPEB Rider

***71** IAWC initially proposed a rider to recover pension OPEB costs. IAWC Ex. 1.00 (Rev.) at 18; *see also* IAWC Ex. 7.00 at 20-25; IAWC Ex. 7.00R (Rev.) at 17-21. In order to narrow the issues, however, IAWC withdrew this proposed rider. IAWC Ex. 7.00SR (Rev.) at 10. IAWC asserts that it reserves the right to propose a Pension/OPEB rider in future cases. *Id.* The Commission makes no findings regarding the terms of the proposed rider and it has not been considered for approval by the Commission.

B. Contested Issues

1. Rider VBA

a. IAWC's Position

IAWC asserts that most of its costs are fixed and it is experiencing both declining and variable usage. The Company explains that the Commission and the Illinois Supreme Court have found that decoupling a utility's sales and revenues—by truing up rates to approved revenues—addresses these cost recovery problems. The Company, therefore, states that it is proposing a decoupling mechanism, Rider VBA, to resolve its cost recovery concerns.

IAWC reiterates that like gas utilities, most of its costs are fixed, and do not vary with usage. IAWC Ex. 7.00 at 4-5. However, under traditional ratemaking, it relies on volumetric charges (which are based on the number of gallons of water a customer consumes), to recover the majority of its costs. *Id.* at 5. Thus, IAWC states that its cost recovery is heavily dependent on water sales volume which can be a source of fiscal stress for the Company because declining usage, weather, or both, can push IAWC's sales volumes, and so revenues, below the point where the utility has a reasonable opportunity to recover its costs. The Company also states that its dependence on volumetric sales for revenue creates an incentive to sell more water and a disincentive to promote water efficiency. *Id.*

According to IAWC, its proposed Rider VBA would address these issues. The Company states that Rider VBA is designed to ensure that it collects the revenues authorized by the Commission, independent of changes in sales volume. *Id.* at 8. Rider VBA, IAWC explains, would compare the rate case authorized amount of volumetric revenues to actual volumetric revenues, net of production expenses (power, chemicals, and water waste disposal) that vary directly with sales levels, and provide a credit (if revenues exceed the authorized level) or a volumetric surcharge (if revenues are below the authorized level). *Id.* at 11-12. Netting production costs will ensure that customers pay only those production costs for the actual amount of water delivered. *Id.* at 12. The Company further explains that under Rider VBA, prices will increase and decrease as sales volume changes between rate cases but it will hold revenues at authorized levels. *Id.* at 9.

Additionally, IAWC states that Rider VBA removes the incentive to sell more water and any disincentive to promote water efficiency, reduces the adverse impacts of weather variability for both IAWC and its customers, and supports revenues for programs and investments that improve water efficiency. *Id.* at 10. IAWC explains that Rider VBA also allows for periodic adjustments (credits and surcharges) in between rate cases and therefore IAWC will not need to file frequent rate cases to recover revenue shortfalls resulting from declining sales. *Id.* at 11. IAWC asserts that customers will benefit from a reduction in contested issues in rate cases, a reduction in the frequency of rate cases, and as a result, reduced rate case expense. *Id.*

***72** The Company notes that the Commission has previously approved the Rider VBA decoupling mechanism to address concerns about declining and variable usage. IAWC points to the Rider VBA proposed by North Shore and Peoples Gas ("North Shore/Peoples Gas Rider VBA") which was approved by the Commission as a pilot in Docket Nos. 07-0241/07-0242 (Consol.) in 2008 and permanently in Docket Nos. 110280/11-0281 (Consol.) in 2012. *See* Docket Nos. 07-0241/07-0242 (Consol.), Order at 150; Docket Nos. 11-0280/11-0281 (Consol.), Order at 164. The Company also points to the Rider VBA proposed by Ameren Illinois Company d/b/a Ameren Illinois ("Ameren Rider VBA") in Docket No. 15-0142 which the Commission recently approved in 2015. Docket No. 15-0142, Order at 109. IAWC elaborates that the Ameren Rider VBA is very similar to the North Shore/Peoples Gas Rider VBA and it was approved by the Commission as an uncontested issue. The Company further notes that its Rider VBA is modeled after the North Shore/Peoples Gas Rider VBA.

IAWC highlights that the Rider VBA decoupling mechanism is legally sound. To support its point, the Company notes that the Illinois Supreme Court recently affirmed that the North Shore/Peoples Gas Rider VBA approved in the Commission's Order in Docket Nos. 11-0280/11-0281 (Consol.) is lawful, holding that the rider did not violate either the prohibition against single-issue ratemaking or the rule against retroactive ratemaking. *People ex rel. Madigan v. Ill. Commerce Comm'n,* 2015 IL 116005 at ¶ 3.

Finally, the Company notes that IAWC, Staff, the AG and IIWC/FEA are now in agreement that Rider VBA should be adopted and that it should reflect Staff witness Brightwell's proposal to recover only volumetric costs through the rider as well as Dr. Brightwell's rider formula. The Company asserts, however, that the AG continues to propose additional modifications to IAWC's Rider VBA. Specifically, the AG recommends that a separate Rider VBA should be created for Zone 1 purchased water areas (Chicago Lake and South Beloit) and that Rider VBA should be eliminated for Chicago Wastewater. IAWC opposes the AG's proposals and maintains that they should be rejected.

With respect to the first recommendation, IAWC contends that a separate Rider VBA for purchased water areas will cause the rider to become administratively burdensome, which the AG does not dispute. Moreover, IAWC asserts that the AG unconvincingly argues that it would be unfair to the customers of the purchased water areas to reject the AG's proposal because the variable costs for customers in these areas are not recovered through base rates and there are rate impacts of 0.3 - 2.0% that AG witness Rubin claims are significant.

***73** IAWC takes issue with this argument for several reasons. First, the Company states that it is not true that all purchased water customers' variable costs are excluded from base rates. IAWC explains that Chicago Metro Lake and South Beloit have production costs for power used to pump water through the system that are not included in the purchased water charges. IAWC Ex. 7.00R (Rev.) at 9. IAWC points out that Mr. Rubin acknowledged as much in his rebuttal testimony. AG Ex. 4.0 at 4. Because of this, IAWC states, Chicago Metro Lake and South Beloit are no different from a rate consolidation perspective than other areas in the consolidated Rate Zone 1, as costs vary from area to area. Therefore, creating a separate Rider VBA for these purchased water areas would effectively undo the consolidation of these areas into Zone 1. IAWC Ex. 7.00SR (Rev.) at 5. Second, the Company states that, contrary to the AG's assertion, there will not be any material impact on customer bills from separating purchased water areas. IAWC argues that Mr. Rubin's assessment of ratepayer impact of 0.3 - 2.0% is overstated. IAWC Ex. 7.00SR (Rev.) at 6. According to the Company, the impact to a customer's monthly bill is 0.309% and 0.506% for Chicago Lake and South Beloit, respectively. *Id.* at 7-8. IAWC concludes that there is little point to the AG's proposal since there is not a significant difference in customers' bills from separating purchased water customers. IAWC Ex. 7.00R (Rev.) at 7-8.

With respect to the second recommendation, IAWC contends that Rider VBA is needed for Chicago Wastewater. The Company states that, like its water rate areas, its sewer rate area's fixed revenues do not recover the full amount of fixed costs, therefore its fixed cost recovery in its sewer rate area is also dependent on usage volumes. *Id.* at 13. IAWC points out that 92% of the costs in the Chicago Wastewater district are fixed; however, fixed wastewater revenues proposed in this case are only 81.8%. *Id.* The Company argues that since the fixed costs are not recovered by the fixed revenues, Rider VBA is needed here to ensure the Company recovers the fixed costs of service.

b. Staff's Position

Staff observes that both Staff witnesses Brightwell and Hathhorn proposed revisions to the Company's Rider VBA proposal. Staff asserts that Staff witness Brightwell proposed limiting revenue reconciliations to differences between actual distribution delivery charge revenues and rate case distribution delivery charge revenues and opined that adjustments to production costs should be based on the average rate case production cost multiplied by the difference between actual sales and rate case sales in each rate zone. Staff Ex. 8.0 at 7-8. Staff notes that the Company agreed to these changes (IAWC Ex. 7.00SR at 2) and provided suggested language for the rider as Exhibits 7.01SR and 7.02SR.

Staff states that Ms. Hathhorn proposed changes to the proposed Rider VBA concerning customer acquisitions, internal audit, reports and reconciliations, and corrections to the formula and the water production costs definition in the wastewater tariff. Staff notes that the Company also accepted these changes. IAWC Ex. 7.00R at 3.

***74** Staff mentions that Ms. Hathhorn also recommended that the Company present proposed language and/or a separate tariff in its rebuttal testimony to address the fact that Chicago Metro Lake customers do not pay production costs through base rates. Staff Ex. 2.0 at 13. However, Staff states that it withdrew this recommendation based on the Company's explanation that its IAWC Exhibit 7.01R does not segregate the Chicago Metro Lake or South Beloit customers into separate tariffs because the Company believes this would cause the Rider VBA to become administratively burdensome. IAWC Ex. 7.00R at 8; Staff Ex. 10.0 at 5-6.

Staff concludes that it supports the Company's Rider VBA with these agreed upon modifications. Staff notes that the traditional rate-setting paradigm was established at a time when utilities experienced regular and predictable customer and sales growth; however, an increased focus on energy efficiency and conservation efforts has caused this paradigm to shift somewhat. Staff asserts that, while there is nothing wrong with the traditional method of rate setting, the Company has identified many problems it is facing within the traditional paradigm due to sales variability and the Company has established that Rider VBA alleviates many of these problems.

c. AG's Position

The AG states that it does not oppose the Company's proposed Rider VBA in concept, but it recommends changes to the tariff. The AG notes that it reached an agreement with IAWC, as reflected in IAWC-AG Stipulated Cross-Exhibit 2.00, to accept Staff witness Brightwell's proposal that the Company should recover only volumetric charges through Rider VBA and use Dr. Brightwell's suggested tariff formula. IAWC-AG Stip. Cross-Ex. 2.00 at 1. The AG notes that, like Dr. Brightwell, AG witness Rubin testified that the rider, as originally proposed, would inappropriately recover certain variable costs and that these variable costs should not be recovered through Rider VBA. AG Ex. 2.0 at 14. The AG submits that this change is perhaps the most significant change.

While the AG agrees with Staff and IAWC on those points, the AG states that it recommends two additional changes to the Company's Rider VBA. The AG argues that IAWC's Rider VBA should be modified to require the Company to calculate separate Rider VBA charges for the South Beloit and Chicago Metro Lake areas of Zone 1. The AG notes that Mr. Rubin testified that the Company's proposal is unfair to the South Beloit and Chicago Metro Lake regions because the variable costs for customers in these areas are not recovered through base rates like the customers in all of the other areas in Zone 1. Mr. Rubin explained that customers in the South Beloit and Chicago Metro Lake areas pay their variable costs (consisting of purchased water) through a separate rider and, as a result, pay lower fixed charges than other Zone 1 customers. AG Ex. 2.0 at 15. The AG also notes that, in response to an AG discovery request to IAWC, the Company agreed that it is appropriate to calculate a separate Rider VBA charge for the South Beloit and Chicago Metro Lake regions. AG Ex. 4.0 at 3; AG Ex. 4.1. However, the AG asserts that IAWC witness Watkins later testified in rebuttal testimony that the administrative burdens would be too great, and the rate impacts too small, to justify separate Rider VBA charges for these areas. IAWC 7.00R at 9-11.

***75** The AG challenges Mr. Watkin's characterization that the rate impacts are insignificant. The AG states that Mr. Rubin's calculations of the percentage of fixed charges for these areas show that IAWC's proposed rate for 100 gallons of water for customers in the portions of Zone 1 that do not purchase water (that is, areas other than South Beloit and Chicago Metro Lake) would change by as much 2%. AG Ex. 2.6; AG Ex. 4.0 at 3-4. Mr. Rubin's analysis also shows, in the AG's view, that the rate adjustments for the South Beloit and Chicago Metro Lake areas would be 1.9% and 0.3% of base rates in 2013, respectively. *Id.* at 4; AG Ex. 4.3. The AG contends that, contrary to Mr. Watkins' assertion, such impacts on base rates are significant and justify separate Rider VBA calculations for the purchased water areas of Zone 1. AG Ex. 4.0 at 4-5.

The AG also argues that wastewater customers should be exempt from the tariff. The AG asserts that there is no reason to apply Rider VBA to wastewater customers because unlike water revenues, approximately 85% of the Company's wastewater revenues are fixed, therefore these customers pay a flat rate that varies very little from month-to-month. AG Ex. 2.0 at 15-16.

For these reasons, the AG recommends that the Commission accept its recommendation to modify Rider VBA to require IAWC to: (1) calculate separate Rider VBA charges for the South Beloit and Chicago Metro Lake areas of Zone 1; and (2) exclude wastewater customers from the tariff.

d. IIWC/FEA's Position

IIWC/FEA state that, in the interest of narrowing the issues in this case only, they do not oppose the Company's proposal to accept Staff witness Brightwell's proposal to recover only volumetric revenues through Rider VBA and his formula methodology for Rider VBA. IAWC Ex. 7.00SR at 2.

e. Municipalities' Position

The Municipalities observe that IAWC has modified its proposed Rider VBA based on changes suggested by Staff which limit the rider's impact on ratepayers. *Id.* The Municipalities state that they do not oppose the adoption of Rider VBA, provided that Staff's changes are included as part of the rider.

f. Commission Analysis and Conclusion

The Company proposes a Rider VBA decoupling mechanism to address its cost recovery concerns. Staff witnesses Hathhorn and Brightwell proposed several modifications to the Company's Rider VBA, including a proposal that the rider should only recover volumetric charges and that it should use the rider formula proposed by Dr. Brightwell. The Company accepts these modifications and Staff supports the rider with these modifications. The AG, IIWC/FEA, and the Municipalities do not oppose the Company's Rider VBA as revised by Staff; however, the AG proposes additional modifications which the Company opposes.

The Commission finds that IAWC's Rider VBA is reasonable and appropriate in these circumstances. The record supports the Company's assertion that most of its costs are fixed and that it is experiencing both declining and variable usage. Additionally, IAWC has established that both weather and declining usage per customer has caused its sales volumes and revenues to vary from approved levels. While there is nothing wrong with traditional ratemaking, the Commission has determined in Docket Nos. 07-0241/07-0242 (Consol.), Docket Nos. 11-0280/11-0281 (Consol.), and recently in Docket No. 15-0142, that decoupling mechanisms such as Rider VBA address these cost recovery issues.

***76** The Commission notes that under traditional ratemaking, the Company relies on volumetric charges to recover the majority of its costs. Thus, IAWC's cost recovery is heavily dependent on water sales volume which can be problematic because declining usage can drive IAWC's sales volumes, and therefore revenues, below the point where the utility has a reasonable opportunity to recover its costs. The Company's dependence on volumetric sales for revenue creates an incentive to sell more water and a disincentive to promote water efficiency.

The Commission believes Rider VBA resolves these issues by producing a determined amount of revenue regardless of how much water a utility delivers, and therefore it ensures that the utility can recover its Commission-authorized revenue requirement. Rider VBA also removes the incentive to sell more water and any disincentive to promote water efficiency, reduces the adverse impacts of weather variability for both IAWC and its customers, and supports revenues for programs and investments that improve water efficiency. The rider also benefits IAWC's customers because it allows for periodic adjustments (credits and surcharges) in between rate cases therefore the Company will not need to file frequent rate cases to recover revenue shortfalls resulting from declining sales. IAWC customers will also benefit from reduced rate case expense because there will be a reduction in contested issues in rate cases and a reduction in the frequency of rate cases.

Finally, the Commission observes that the Company's Rider VBA is modeled after the North Shore/Peoples Gas Rider VBA. The Illinois Supreme Court has affirmed the Commission's Order in Docket Nos. 11-0280/11-0281 (Consol.) adopting this Rider VBA decoupling mechanism permanently and it found that it is lawful. For these reasons, the Commission approves the Company's Rider VBA as modified by Staff.

The Commission, however, declines to adopt the modifications proposed by the AG. The AG recommends that a separate Rider VBA should be created for Zone 1 purchased water areas (Chicago Lake and South Beloit) and that Rider VBA should be eliminated for Chicago Wastewater. The Commission finds that the Company has shown that the AG's first recommendation is administratively burdensome, contrary to the Commissions recent decision in IAWC's last rate case to consolidate Zone 1, and it appears that it will have little impact on customers' bills. The Commission also finds that the Company has shown that the AG's second recommendation should be denied because IAWC's sewer rate areas face the same issue as its water rate areas since the fixed revenues for these areas do not recover the full amount of fixed costs either. Therefore, Rider VBA will help ensure that the Company recovers the fixed costs of service in the sewer rate areas also.

2. Rider QIP Recommendation

a. IAWC's Position

***77** IAWC notes that it included in its rate base investments that would qualify as QIP investments under 83 Ill. Admin. Code 656 (“Part 656”). The Company states that it agreed with Staff witness Hathhorn's proposal to attach the QIP amounts as an appendix to the Commission's final Order, with the caveat that the information would no longer be accurate if new rules are approved since the information is based on the Commission's Part 656 Rules in effect in January 2016. IAWC Ex. 4.00R at 5.

IAWC observes that new rules were approved by the Commission in Docket No. 15-0017 and they became effective as of July 1, 2016 in Docket No. 15-0017. *See* Part 656; *Aqua Ill., Inc.*, Docket No. 15-0017, Order at 2 (June 29, 2016). Therefore, IAWC states, in its Reply Brief, that it is unnecessary to attach the information because it is outdated and no longer accurate. The Company explains that updated information regarding the QIP investments will be available after the first quarter of 2017.

b. Staff's Position

Ms. Hathhorn recommended, for purposes of a complete record and possible use in future proceedings, that the QIP amounts provided by IAWC should be attached as an appendix to the Commission's final Order in this case. Staff Ex. 2.0 at 6. Ms. Hathhorn testified in her rebuttal testimony that the Company agreed with her recommendation. Staff Ex. 10.0 at 4-5.

In its Brief on Exceptions, Staff states that it withdraws its recommendation because the recently revised Part 656 now requires a post-rate case filing of the calculation of updated QIP plant and depreciation amounts, rendering its recommendation moot.

c. Commission Analysis and Conclusion

The Commission concurs with Staff that its recommendation is now moot. Both IAWC and Staff agree that Part 656 now requires a post-rate case filing of QIP information. Moreover, Staff has withdrawn its recommendation since it was based upon the prior Part 656 Rules. Therefore, the Company does not need to attach the QIP amounts as an appendix to this Order.

VI. RATE DESIGN AND COST OF SERVICE

A. Resolved Issues

1. Declining Block Usage Charge for Non-Residential Customers in Chicago Metro Sewer

Staff witness Boggs recommended that IAWC continue to apply a declining block usage charge to Collection Only and Collection and Treatment customer classes in the Chicago Metro Sewer District, as had been approved in prior cases. Staff Ex. 6.0 at 22. IAWC accepted this proposal. IAWC Ex. 11.00R at 5. The Commission finds that Staff's proposal to apply a declining block usage charge to Collection Only and Collection and Treatment customer classes in the Chicago Metro Sewer District is reasonable and it is hereby approved.

2. Public Fire Charges

***78** Staff witness Boggs recommended that the Public Fire Protection rate for each of IAWC's three water districts be set so that the revenues recovered are equal to the cost to serve the respective district. Staff Ex. 6.0 at 29. Staff's proposed adjustments increase the Public Fire Protection rates in Zone 1 and Lincoln and decrease the rates in Pekin. *Id.* at 29-30. IAWC did not object to Staff's proposal. IAWC Ex. 11.00R at 5. The Commission finds that the adjustments to the Public Fire Protection rates proposed by Staff and agreed to by the Company, are reasonable and they are hereby adopted for the purposes of this proceeding.

3. Certain Large User

IIWC/FEA witness Collins and IIWC/FEA/CUB witness Gorman recommended that IAWC include a certain customer in the Large Industrial class in its cost of service study ("COSS") that IAWC originally excluded from the study. IIWC/FEA Ex. 1.0 at 7; IIWC/FEA/CUB Ex. 1.0 at 6. Mr. Collins testified that, although the customer's usage had "declined due to economic circumstances," the customer "did not intend to cease all operations at its facilities served by IAWC." IIWC/FEA Ex. 1.0 at 7. IAWC proposed to account for the decline in the customer's usage by utilizing the customer's most recent 12-month usage level. IAWC Ex. 4.00R at 21-22. Mr. Collins and Mr. Gorman agreed that this revised usage is reasonable. IIWC/FEA Ex. 2.0 at 3; IIWC/FEA/CUB Ex. 2.0 (Rev.) at 2-3. The Commission finds that the use of the large customer's usage from the most recent 12-month period in IAWC's COSS is appropriate and it is hereby accepted for the purposes of this proceeding.

4. Distribution Main Allocation to Large Users

AG witness Rubin proposed to modify IAWC's Factor 4, which allocates costs associated with distribution mains for purposes of the COSS. AG Ex. 2.0 at 5-7. According to IAWC, its proposed Factor 4 excludes usage from the Large Commercial, Large Industrial, Competitive Industrial, Large Other Public Authority, Other Water Utilities, and Large Other Water Utilities classes because generally, these customers are served from transmission mains, rather than distribution mains. IAWC Ex. 11.00R at 11. Mr. Rubin testified that the usage from eleven of the thirty-four customers excluded from the allocation of distribution main costs should be added to IAWC's Factor 4 calculation because he determined that they are served by distribution mains. AG Ex. 2.0 at 5-7. IAWC witness Herbert, however, testified that he determined that six of the eleven customers at issue were served by short stub distribution-diameter mains, and should not be considered connected to distribution mains. IAWC Ex. 11.00R at 11. Mr. Herbert further testified that the remaining five customers could be considered served from a distribution main, and added their consumption into the calculation of Factor 4. *Id.* The AG agreed with IAWC's revised Factor 4. AG Ex. 4.0 at 7. The Commission finds that revised Factor 4, as agreed upon by the AG and IAWC, is reasonable and it is hereby adopted for the purposes of this proceeding.

B. Contested Issues

1. Purchased Power Cost Allocation

a. IAWC's Position

***79** IAWC states that its COSS properly allocates purchased power costs using Factor 1, which is based on average daily usage. The Company urges the Commission to reject IIWC/FEA's recommendation that IAWC's purchased power costs should be allocated using Factor 6, which is based on maximum day and hour demands. IIWC/FEA Ex. 1.0 at 17.

IAWC notes that IIWC/FEA witness Collins testified that Factor 6 allocation is appropriate because that factor "recognizes the base and extra capacity components of purchased power costs, and is consistent with the allocation of IAWC's other pumping expenses and the allocation of rate base associated with electric pumping equipment." IIWC/FEA Ex. 1.0 at 17. IAWC contends that Mr. Collins' assertion, which is the basis for IIWC/FEA's recommendation, is flawed.

First, the Company asserts that contrary to Mr. Collins' assertion, Factor 6 does not accurately account for the base and extra capacity components of IAWC's purchased power costs. IAWC explains that electric rates are structured to include three components: a customer charge, a demand charge, and commodity charges. IAWC Ex. 11.00R at 7. The Company observes that the American Water Works Association Manual M1 ("AWWA Manual") provides that "the demand portion of power costs should be allocated to extra capacity to the degree that it varies with the demand pumping requirements." *Id.* IAWC states its electricity bills include a demand charge, even when the Company is at its lowest demand for power, and explains this is the base component of IAWC's purchased power costs. The Company further explains that the extra capacity component of purchased power costs is the amount by which the demand charge varies with the demand pumping requirements. IAWC points out that its witness Mr. Herbert determined that only 1.25% of IAWC's total purchased power expense is attributable to extra demand. *Id.* IAWC states that if Factor 6 was applied to purchased power costs, as Mr. Collins proposes, 42.6% of IAWC's power costs would be allocated to extra demand. *Id.* Thus, IAWC maintains that the application of Factor 6 clearly does not accurately account for the base and extra capacity components of IAWC's electric demand costs.

Second, the Company states that even though Factor 6 is used to allocate non-power pumping costs, it is not an appropriate allocator for purchased power costs. IAWC notes that purchased power is conceptually similar to other costs allocated using Factor 1, such as purchased water, treatment chemicals, and sewer disposal. IAWC Ex. 11.00 (Rev.) at 6. IAWC also points out that Factor 6 is appropriate for the "capital and associated O&M costs because the system is designed to meet average demand and as well as maximum day and hour demands." IAWC Ex. 11.00R at 6. However, IAWC states that unlike the capital and O&M costs, the power that runs the pumping facilities "varies with the amount of water being pumped, and varies only minimally with peak usage." *Id.* at 7. IAWC argues that because purchased power varies only minimally with peak usage, Factor 1, which is based on average daily consumption, is a more reasonable and appropriate allocator.

***80** Finally, IAWC asserts that IIWC/FEA also argue, for the first time in their Initial Brief, that class contributions to peak water demands vary, particularly for the residential class, and that variation in peak power demand among the rate classes is not accounted for in Factor 1. IAWC contends that this argument also fails to withstand scrutiny. IAWC points out that IIWC/FEA never mentioned residential class power demand costs in the testimony they offered in this case, let alone establish that class contributions to peak power demand vary between winter and summer months due to residential and commercial irrigation demands. Thus, IWAC asserts that there is no record evidence to support this late argument.

For these reasons, IAWC concludes that the Commission should reject IIWC/FEA's recommendation to utilize Factor 6 rather than Factor 1 to allocate IAWC's purchased power costs.

b. Staff's Position

It is Staff's position that the Commission should reject IIWC/FEA's proposal to allocate purchased power costs using Factor 6 instead of Factor 1 in the Company's COSS. Staff argues that IIWC/FEA's proposal is untenable because it fails to recognize that, unlike the other costs associated with pumping water, purchased power costs vary with the amount of water being pumped and vary only minimally with peak usage.

Staff observes that IAWC witness Herbert explained in his testimony that, while using Factor 6 as an allocator for capital costs and O&M costs associated with pumping equipment is appropriate, using Factor 6 as an allocator for the power costs associated with pumping is not. IAWC Ex. 11.00R at 6-7. He testified that Factor 6, which uses average flow and maximum day and hour requirements, aligns with the purposes of the pumping system because the pumping system is designed to meet average demand as well as maximum day and maximum hour demands. *Id.* Staff notes that Mr. Herbert concluded that, because the power to run the pumps varies with the amount of water being pumped, it only varies minimally at peak usage. Mr. Herbert asserted that Factor 1 is therefore appropriate in IAWC's COSS because it is based on average daily usage. *Id.* at 7.

Staff also observes that Mr. Herbert supported his allocation method by quoting the AWWA Manual which states that "the demand portion of power costs should be allocated to extra capacity to the degree that it varies with the demand pumping requirements." IAWC Ex. 11.00R at 7. Mr. Herbert explained that the AWWA Manual does not suggest that the total demand portion of power costs should be allocated to extra capacity, rather it should be allocated only to the degree that it varies with pumping requirements. *Id.*

Additionally, Staff notes that Mr. Herbert testified that he analyzed the Company's power bills and determined that they show that the difference between the minimum demand charge for the lowest demand month and the demand charges in the remaining months result in approximately 1.25% of the total purchased power expense being attributable to extra demand. *Id.* On the other hand, he testified that using Mr. Collins' Factor 6 proposal would allocate about 42.6% of power costs to the extra demand functions. *Id.* Staff highlights that Mr. Herbert also stated that an accurate refinement to the Company's COSS based on the power bill analysis would allocate only 1.25% of purchased power costs to the extra capacity function. *Id.* Staff notes that Mr. Herbert further stated that an adjustment should not be made because such a small refinement (1.25%) would have an insignificant impact on the COSS. *Id.* at 8.

***81** Staff avers that Mr. Herbert's testimony supports IAWC's use of Factor 1 to allocate purchased costs instead of Factor 6 as IIWC/FEA recommend. Staff argues that IAWC's method better reflects cost of service and it is based on the AWWA Manual's procedures which are commonly used in COSSs and rate designs. Moreover, Staff contends that IIWC/FEA failed to provide convincing reasons or data that would justify the need to deviate from the previously approved process. Accordingly, Staff asserts that the Commission should approve the Company's proposal to use Factor 1 to allocate purchased power costs instead of Factor 6.

c. IIWC/FEA's Position

While IIWC/FEA generally agree with the cost classifications and allocations contained within the Company's COSS in this proceeding, IIWC/FEA disagree with the allocation of purchased power costs through the use of Factor 1. IIWC/FEA recommend that IAWC allocate these costs using Factor 6 instead.

IIWC/FEA argue that Factor 6 is more appropriate because this allocation factor recognizes the base and extra capacity components of purchased power costs, and is consistent with the allocation of IAWC's other pumping expenses and the allocation of rate base associated with electric pumping equipment.

IIWC/FEA assert that it is important to note that all of the costs associated with pumping, except for purchased power, have been allocated based on Factor 6 and purchased power costs are the only costs associated with pumping to be allocated on the basis of Factor 1. IIWC/FEA state that Factor 6 recognizes the Company's rate classes' contribution to peak water demands. They argue that the Company's allocation of purchased power cost associated with pumping is inconsistent with the treatment of other expenses and rate bases associated with pumping. This inconsistency is unreasonable according to IIWC/FEA because purchased power costs are not all driven by average daily water consumption upon which Factor 1 is based. IIWC/FEA note the other costs (both expenses and capital) associated with pumping have been recognized by the Company to have both a base component as well as an extra capacity component and have been allocated appropriately on Factor 6. IIWC/FEA Ex. 1.0 at 16.

It is IIWC/FEA's position that the Company's arguments fail to recognize the class contributions to purchased power costs which are driven by class peak demands for water. IIWC/FEA opine that under the Company's logic, if total Company demand costs are the same each month and do not vary, all demand costs would be allocated to customers based on average daily usage or Factor 1. IIWC/FEA aver that the Company's arguments ignore the fact that class contributions to peak water demands vary, particularly for the residential class.

IIWC/FEA state that while the total system demand costs may not vary materially in IAWC's opinion, the reality is that residential class water demands that contribute to these total purchased power costs do vary materially and should be recognized in the allocation of purchase power costs. This recognition of class contributions to system peak water demand is accomplished by Factor 6. IIWC/FEA explain that Factor 6 recognizes the class contributions to peak demand for water which in turn drive the Company's total purchased power costs. IIWC/FEA assert that it is inappropriate that the Company has recognized these class peak demand contributions to all pumping costs except for purchased power costs.

***82** According to IIWC/FEA, electric power demand costs are driven by IAWC's monthly peak electric demand; therefore, the electric power demand costs should be classified as extra capacity costs. IIWC/FEA Ex. 2.0 at 5. IIWC/FEA argue that with the use of Factor 1, the Company fails to properly differentiate between the purchased power cost it incurs on the basis of classes' average daily usage and the purchased power cost incurred on the basis of classes' peaking requirements. With the use of Factor 1, IIWC/FEA claim the Company ignores the effect that class contributions to peak demand have on purchased power costs. IIWC/FEA note that this effect varies particularly between winter and summer months due to residential and commercial irrigation demands. The variation in purchased power costs is based in part on customer class peak demands for water and should be allocated accordingly. Consequently, IIWC/FEA believe their proposal is more appropriate and should be adopted by the Commission.

d. Commission Analysis and Conclusion

IAWC and IIWC/FEA dispute whether the Company should allocate its purchased power costs in its COSS using Factor 1, which is based on average daily usage, or Factor 6, which is based on maximum day and hour demands. The Commission believes the Company provided compelling evidence that demonstrates that Factor 6 is not an appropriate allocator for purchased power costs and it does not accurately account for the base and extra capacity components of the Company's electric demand costs. Additionally, the Company's allocation method better reflects the cost of service and it is based on the AWWA Manual's procedures which are commonly used in COSSs and rate designs. The Commission also notes that the method used by the Company was approved previously in IAWC's last rate case, Docket No. 11-0767, and IIWC/FEA do not provide any convincing reasons or evidence to justify the need to deviate from this previously approved method. Finally, the Commission agrees with the Company that there is no evidence in the record to support IIWC/FEA's argument in their Initial Brief regarding the variations among classes' contributions to peak water demand. Accordingly, the Commission finds that IAWC's proposal to allocate purchased power costs using Factor 1 is reasonable and it is adopted.

2. Simplification of Metered Large User Water Tariff

a. IAWC's Position

IAWC argues that the Commission should disregard IIWC/FEA's proposal to simplify IAWC's Metered Large User Water Service tariff. IAWC explains that this tariff is available to customers that use at least 187 million gallons of water per year. ILL.C.C. No. 24, Sec. 1, Eight Rev. Sheet 14.1. Charges to customers under the tariff are equal to the customer's maximum day demand ratio, multiplied by approximately $0.19. *Id.* The Company states that the maximum day demand ratio is the customer's maximum day demand divided by the customer's average day demand. *Id.* IAWC claims that the maximum day demand ratio serves two important purposes. First, it incentivizes customers to smooth their demand so that their maximum day demand is as close as possible to their average day demand, because it increases charges when the maximum demand is higher than average demand. IAWC Ex. 11.00SR at 8. Second, IAWC explains, the maximum day demand ratio variable in the current tariff ensures that customers' rates are determined individually, and customized to match their usage. *Id.*

***83** The Company notes that in his direct testimony, IIWC/FEA witness Collins proposed that IAWC's Metered Large User Water Service tariff "should be simplified … to provide more cost certainty to customers" served under the tariff and attract additional customers to the tariff. IIWC/FEA Ex. 1.0 at 18. However, IAWC argues that Mr. Collins did not offer any substantive suggestion as to how the tariff should be simplified, or explain why such simplification is desirable. IAWC states that although Mr. Collins did not specify which portion of the existing formula he proposed to eliminate, IAWC witness Herbert surmised that Mr. Collins' concern is rooted in the fact that the current tariff includes a variable for customers' Maximum Day Demand Ratio. As discussed above, IAWC states that the maximum day demand ratio serves important purposes, provides appropriate incentives, and should not be eliminated.

IAWC states that IIWC/FEA's alternative proposal that the Commission should order the parties to participate in a workshop to discuss possible revisions to this tariff should be rejected. The Company argues that there is no reason to hold a workshop on this matter since IIWC/FEA have not made a specific, substantive suggestion in this proceeding. IAWC argues that IIWC/FEA had multiple opportunities to put forth a substantive proposal in this proceeding, yet failed to do so. It is IAWC's view that the Company and other parties to a workshop would be burdened to develop the proposal IIWC/FEA should have developed during the course of this proceeding.

Moreover, IAWC maintains that the rationale IIWC/FEA offer in support of their proposed simplification is fallacious. Mr. Collins noted that only two customers currently take service under the Metered Large User Water Service tariff and he stated that simplifying the tariff would be beneficial because it would "attract additional customers to take service under this tariff." *Id.* IAWC states, however, that if Mr. Collins' proposal is adopted and successful in attracting additional customers to the tariff, there may well come a point at which it is more efficient to use a formula, which IAWC's tariffs currently utilize, than to calculate rates at the cost of service. IAWC Ex. 11.00R at 8-9. IAWC states that this further supports its position that there is no need to make unspecified and unsupported changes to the tariff. Therefore, IAWC asks that the Commission reject IIWC/FEA's proposal.

b. Staff's Position

Staff asserts that the Commission should reject IIWC/FEA's proposal to simplify IAWC's Metered Large User Water Service tariff. Staff agrees with IAWC that IIWC/FEA witness Collins did not provide a specific proposal regarding eliminating the rate formula in the Metered Large Water Service tariff. Rather, he simply indicated the rate should be based on the cost of providing service to customers. Staff states that while it generally supports setting cost-based rates, it must be able to review specific descriptions and/or calculations of a cost-based rate design to determine whether the recommended design is one that can be usefully developed to recover costs and mitigate rate impacts for a specific customer class. Without a specific rate design proposal for these customers, Staff maintains that there is insufficient information to assess the merits of IIWC/FEA's recommendation and therefore it should not be adopted.

c. IIWC/FEA's Position

***84** IIWC/FEA recommend that IAWC simplify its Metered Large User Water Service tariff by eliminating the rate formula in the tariff. IIWC/FEA Ex. 1.0 at 18. IIWC/FEA argue that IAWC should instead base the rate on the utility's cost of providing service to customers served under the tariff. *Id.*

IIWC/FEA observe that currently only two customers receive service under this tariff and IIWC/FEA argue that simplification of the tariff will encourage other eligible customers to take this service. Moreover, IIWC/FEA believe simplification is possible and will provide more revenue certainty to the Company and more cost certainty to customers at a time when IAWC claims the need for a new rider due to uncertain cost recovery.

IIWC/FEA disagree with the Company's argument that their proposal will not simplify the tariff or the rate charged to customers under the tariff and that IIWC/FEA do not describe how IAWC would charge customers under this proposal. IIWC/FEA state that their witness Mr. Collins did in fact offer a specific proposal. *Id.*

IIWC/FEA take issue with the Company's argument that, assuming Mr. Collins is correct and the modification does attract additional customers, at some point a rate formula may be more efficient. IIWC/FEA state that while this may be a future concern for IAWC, any changes necessary to the rate could and should be made in the next rate case based on the customer situation at that time. The Company should not keep a less efficient tariff because at some point in the future the current less efficient method may be more appropriate. IIWC/FEA argue that they have shown the benefits of revenue certainty, customer cost certainty, and the incentive for more customers to apply for service under this proposed tariff, outweigh the concern that another method might be more efficient at some point in the future.

It is IIWC/FEA's position that the Company can ably modify the tariff as recommended noting, in general, utility companies routinely create new tariffs and modify existing tariffs outside rate cases. Should the Commission reject the IIWC/FEA recommendation, IIWC/FEA assert that it would be prudent to establish a workshop among the parties involved in this rate case, and any other interested stakeholders, to discuss possible revisions to this tariff to both simplify it and to attract additional customers to take service. IIWC/FEA suggest the workshop begin 45 days after the final Order in this docket is issued and conclude 90 days thereafter. They also suggest that Staff file a report 45 days after the conclusion of the workshop that includes a description of the positions of the workshop attendees and Staff's recommendation as to if or when the modified tariff should be filed.

d. Commission Analysis and Conclusion

The Commission observes that IIWC/FEA propose that IAWC simplify its Metered Large User Water Service tariff by eliminating the rate formula in the tariff. IIWC/FEA argue that IAWC should instead base the rate on the utility's cost of providing service to customers served under the tariff. They assert that this modification will provide more cost certainty to customers served under the tariff and encourage more eligible customers to use the tariff. In the alternative, IIWC/FEA propose that the Commission order a workshop to facilitate discussion regarding possible revisions to the tariff if the Commission does not adopt IIWC/FEA's initial proposal.

***85** The Commission finds that IIWC/FEA did not present a sufficiently detailed proposal for consideration in this proceeding or in a workshop. The proposal does not specify which portion of the existing formula IIWC/FEA seek to eliminate or any specific descriptions or calculations of the recommended rate design. IIWC/FEA also failed to present a convincing argument to support the need for their proposal. However, IAWC established that the maximum day demand ratio that appears in its current ratio serves important purposes and provides appropriate incentives. Specifically, IAWC witness Herbert explained that the maximum day demand ratio provides incentives to very large users of water to smooth their demand in a way that minimizes the need for costly extra capacity and peak facilities. For these reasons, the Commission declines to adopt IIWC/FEA's proposal to modify IAWC's Metered Large User water tariff and their alternative proposal to require the parties to participate in a workshop on this issue.

3. Customer Records, Collection Labor, Uncollectible Accounts

a. IAWC's Position

IAWC notes that AG witness Rubin recommended that customer accounts and uncollectibles expenses should be recovered through volumetric charges, rather than fixed customer charges so that residential customers contribute "an equivalent percentage of their bill to support billing, collections, and uncollectible accounts," rather than an equal dollar amount. AG Ex. 2.0 at 8; AG Ex. 4.0 at 6. Mr. Rubin argued that, although "there is no single 'right way' to collect these funds from customers," his methodology "is fairer to all residential customers." AG Ex. 4.0 at 6.

IAWC responds that Mr. Rubin's proposal is not fairer to customers since "there is no difference in the cost to generate and collect a water bill for $40, and the cost to generate and collect a water bill for $80 (or $100, $500, or $1000)." IAWC Ex. 11.00SR at 3. IAWC explains that it incurs customer accounts and uncollectibles expenses on a per-bill basis, not based on the dollar amount of the bill. IAWC asserts that the AG has offered no evidence that the cost to IAWC varies according to the dollar amount of bills, only conclusory statements by its witness with no underlying analysis. *Id.* IAWC notes that Staff agrees that the AG has not provided any evidence that the uncollectible accounts expenses vary with usage or the amount of the bill.

IAWC states that its proposal would collect the same amount from each customer for collections and uncollectible accounts expenses. On the other hand, IAWC notes, the AG's proposal would result in a customer with an $80 water bill paying double the amount of collections and uncollectibles expense that a customer with a $40 water bill would pay, even though the underlying costs to the Company are the same. Thus, IAWC argues that the AG's proposal would cause higher-use customers to subsidize lower-use customers with respect to collections and uncollectibles expenses. IAWC claims that the AG failed to explain why this subsidy is just and reasonable, or why it is fairer. IAWC maintains that the AG's proposal is not fairer, and notes that Staff agrees it is not fair to have high-volume users pay a larger portion of the uncollectible accounts expense than a low-volume user. The Company concludes that the Commission should reject Mr. Rubin's proposal.

b. Staff's Position

***86** Staff disagrees with AG witness Rubin's recommendation that collection expenses and uncollectible accounts expenses should be excluded from the calculation of the customer charge. Staff concurs with IAWC witness Herbert's assessment that Mr. Rubin has not provided evidence that the uncollectible accounts expenses vary with the usage or the amount of the bill. IAWC Ex. 11.00R at 10. Moreover, Staff argues that since collection efforts and expenses to the

Company are the same regardless of the amount of the delinquency, it is not fair to require high-volume users to pay a larger portion of the uncollectible accounts expenses than low-volume customers. Staff Ex. 14.0 at 6-7. Staff further argues that in addition to being unfair, requiring high-volume users to contribute more to the recovery of these expenses would not reflect cost causation. *Id.* It is Staff's position that all customers should share equally in the recovery of these expenses. Therefore, Staff supports the Company's rate design proposal which includes collecting these expenses on a per-customer basis through the customer charge and recommends that the Commission reject the AG's proposal.

c. AG's Position

The AG notes that IAWC proposes collecting collection expenses and uncollectible accounts expenses through the customer charge, making all customers responsible for an equal amount of the expenses. The AG recommends excluding these expenses from the calculation of the customer charge.

AG witness Rubin testified that it is unfair to charge all customers the same amount for these costs because collection expenses and uncollectibles are a function of bill size, which is primarily a function of usage. AG Ex. 2.0 at 8. Mr. Rubin further testified that these costs should be apportioned based on customer usage; that is, customers using greater amounts of water should be responsible for a larger share of collection expenses and uncollectibles than customers using less water. *Id.*

The AG challenges IAWC's argument that Mr. Rubin's proposal should be rejected because "there is no difference in the cost to generate and collect a water bill for $40, and the cost to generate and collect a water bill for $80 (or $100, $500, or $1000)." IAWC Ex. 11.00SR at 3. The AG asserts that IAWC's argument misses the point because Mr. Rubin took no issue with the cost the Company incurs to issue a bill. Rather, while conceding that there is no ""right" answer as to how to recover these costs, Mr. Rubin testified that because there is a relationship between water usage and non-payment, it is fairer that all residential customers pay an equal percentage of their bills toward this cost item, resulting in higher-use customers paying a greater amount of collection expenses and uncollectibles. AG Ex. 4.0 at 6-7. For these reasons, the AG states that the Commission should adopt its proposal to remove collection expenses and uncollectible accounts expenses from the calculation of the customer charge.

d. Commission Analysis and Conclusion

***87** The Commission finds that the record does not support the AG's proposal to recover customer records, collection labor, and uncollectible accounts expenses through volumetric charges rather than customer charges. The AG did not offer any analysis to support its position that these expenses vary based on the size of customers' bills. The Company, however, provided testimony to establish that the collection efforts and expenses to the Company are the same regardless of the size of the delinquent bills. The Company showed that these expenses vary based on the number of customers and therefore all customers should share equally in the recovery of these expenses. Thus, it would be unfair and inconsistent with principles of cost causation to require customers with larger bill amounts to contribute more to the recovery of these expenses than those with smaller bills. Accordingly, the Commission concludes that the Company's rate design proposal which includes collecting these expenses on a per-customer basis through the customer charge is approved and the AG's proposal is rejected.

4. Zone 1 5/8 Meter Charge

a. IAWC's Position

IAWC notes that, as a corollary to his proposed adjustment for customer records, collection labor and uncollectible accounts expenses discussed above, AG witness Rubin proposed an additional adjustment to set the customer charge for Zone 1 customers with 5/8-inch meters to no more than $18.50. IAWC states that Mr. Rubin arrived at this figure by removing the customer records, collection, and uncollectible accounts expenses from IAWC's proposed customer charge. IAWC asserts that the AG offered no compelling support in testimony for its proposal to limit the customer charge to $18.50 and no argument in support of its proposal in its Initial Brief. Therefore, based on these reasons and the reasons explained above, IAWC argues that Mr. Rubin's proposal to remove these expenses from the customer charge should be rejected.

b. Staff's Position

Staff asserts that AG witness Rubin's proposal to limit the monthly Zone 1 charge for a 5/8-inch meter customer to $18.50 due to his proposed adjustments to the customer cost analysis discussed in Section VI.B.3 above is unfounded and should be rejected by the Commission. Staff Ex. 14.0 at 6. Staff argues, as it does in Section VI.B.3 above, that this proposal would not reflect cost causation and it would unfairly require high-volume users to pay a larger portion of the uncollectible accounts expense than low-volume customers. It is Staff's position that uncollectible accounts expense should be recovered on a per-customer basis through the customer charge and therefore the Commission should approve the Company's proposed $20.00 monthly Zone 1 5/8 Meter Charge.

c. AG's Position

As stated in Section VI.B.3 above, AG witness Rubin recommended that the Commission exclude collection expenses and uncollectible accounts expenses from the calculation of the customer charge. Mr. Rubin testified that the result of this proposed adjustment would be an additional adjustment to reduce the customer charge for Zone 1 customers with 5/8-inch meters to no more than $18.50. AG Ex. 2.0 at 8-9. He noted that the Company currently proposes a $20.00 monthly Zone 1 5/8 Meter Charge. Mr. Rubin advanced the same arguments stated above in Section VI.B.3 to support this recommendation. *Id.*

d. Commission Analysis and Conclusion

***88** The Commission declines to adopt AG witness Rubin's proposal to limit the monthly customer charge for Zone 1 customers with 5/8-inch meters to $18.50 due to his recommendation discussed in Section VI.B.3 above to exclude collection expenses and uncollectible accounts expenses from the calculation of the customer charge. As discussed above, the Commission believes the uncollectible accounts expense should be recovered on a per-customer basis through the customer charge and therefore the Commission approves the Company's proposed monthly customer charge of $20.00 for Zone 1 customers with 5/8-inch meters.

5. Limitation of Increase by Class

a. IAWC's Position

IAWC notes that AG witness Rubin proposed that rate increases for all customer classes should be limited so that no class receives an increase of more than 1.5 times the system-average increase, and no class receives an increase that is less than 0.5 times the system-average increase. AG Ex. 2.0 at 10. IAWC states that Mr. Rubin based this proposal on the ratemaking principles of gradualism and rate continuity. *Id.* Although IAWC agrees that generally rate increases should be gradual and continuous, and that the increase limitation is generally reasonable, the Company states that it cannot accept Mr. Rubin's proposal to apply this limitation to all customer classes. IAWC explains that applying this limitation to all rate classes would result in increases to customers that are served under contract. IAWC Ex. 11.00R at 12. IAWC further explains that its contractual rates are fixed in the contracts, which provide the specific provisions for how the rates can be increased. The Company states that the contracts simply do not allow for the increases Mr. Rubin proposes.

IAWC states that it is proposing an overall increase of approximately 21.6% in its rates. Therefore, under Mr. Rubin's proposed limitations, IAWC notes, no class would receive a rate increase of less than 10.8% or more than 32.4%. AG Ex. 2.0 at 10. But in applying these limitations, IAWC states that Mr. Rubin did not account for IAWC's limited ability to increase rates for the customer classes served under contract, which include the Large Commercial, Competitive Industrial, and Large Other Water Utility customer classes. The Company emphasizes that Mr. Rubin's proposal would result in the maximum increase of 32.4% for these customer classes. However, IAWC states, the rates for those classes are set by contract, and the contractual rates cannot be increased as Mr. Rubin proposes. IAWC Ex. 11.00R at 12.

IAWC observes that the AG did not offer any argument in support of this proposal in its briefs. Additionally, IAWC points out that Staff agrees with the theory underlying the AG's proposal — that rate increases should be gradual and continuous, and that the 0.5-1.5 times system-average limitation is generally reasonable. However, both Staff and IAWC agree that the limitation cannot be applied to customer classes that are served under contract. Thus, IAWC concludes that the Commission should reject the AG's proposal.

b. Staff's Position

***89** Staff explains that its witness Mr. Boggs testified that the increase limitations recommended by AG witness Rubin should promote gradualism in rate increases and mitigate any potential for increases that could become burdensome to specific rate classes. Staff Ex. 14.0 at 8. Staff also acknowledges that IAWC witness Herbert testified that the rates for Large Commercial, Competitive Industrial and Large Other Utility are set by contract so the increase limitations proposed by Mr. Rubin would not and could not apply to these customer classes. IAWC Ex. 11.00R at 12.

In light of this testimony, Staff asserts that the Commission should approve Mr. Rubin's recommendation to limit the increase for each customer class so that no class receives a percentage increase that is more than 1.5 times the system average percentage increase or less than 0.5 times the system average increase, but only for those customers who are not bound by the terms of a contract that sets the rates for that respective class.

c. AG's Position

AG witness Rubin recommended that the rate increase for all customer classes be limited so that no class receives an increase of more than 1.5 times the system-average percentage increase, and no class receives an increase that is less than 0.5 times the system-average percentage increase. AG Ex. 2.0 at 4, 10. Mr. Rubin testified that this proposal reflects the principle of gradualism which is an important principle of rate design and cost allocation. Mr. Rubin further testified that under his proposal, each class would receive an increase between 10.8% and 32.4%. *Id.*

d. IIWC/FEA's Position

IIWC/FEA state that they generally agree with the Company's proposed class revenue allocation. IIWC/FEA Ex. 2.0 at 4. However, IIWC/FEA express concern about the Company's proposal for an above system average increase for the Industrial class. IIWC/FEA acknowledge that most increases are difficult for any customer, but IIWC/FEA argue such increases are especially difficult for industrial customers that continuously face competitive pressures in their respective industries throughout the region, the U.S., and the world. *Id.* at 4. IIWC/FEA note such competitive pressures make industrial customers sensitive to even the slightest increases. They argue that while these customers understand such increases are part of doing business, an increase above the system average increase, as is the situation here, is cause for concern which can be alleviated by a more accurate measure of the class cost of service.

IIWC/FEA argue that even with the exemption of the contractual rate customers, the Company's COSS includes several flaws, such as the previously discussed allocation of purchased power expense, which inhibit the Company from accurately measuring the class cost of service. IIWC/FEA assert that, as a result of these inaccuracies, the actual cost of service for the Industrial and Large Other Public Authority classes is lower than the cost of service calculated by the Company in its COSS. *Id.* at 4-5.

***90** Additionally, it is IIWC/FEA's view that application of the AG increase limitation to a flawed COSS still results in increases that are difficult for these classes to sustain. Accordingly, IIWC/FEA believe the Commission should reject the AG's proposal. Instead, IIWC/FEA state that the Industrial and Large Other Public Authority classes should receive increases no higher than those recommended by IAWC witness Herbert, which are 24.5% and 20.7%, respectively. IAWC Ex. 11.00R at 2, 62.

e. Commission Analysis and Conclusion

The Commission notes that the Company proposed an overall increase of approximately 21.6% in its rates which is set forth in detail on page two of IAWC Exhibit 11.01R. In its direct testimony, the AG recommends that the rate increase for all customer classes should be limited such that no class receives an increase of more than 1.5 times the system-average increase, and no class receives an increase that is less than 0.5 times the system-average increase.

The Commission agrees with Staff, IAWC, and the AG that gradualism is an important principle of rate design and cost allocation. However, the Commission declines to adopt the AG's proposal at this time. The AG did not respond to IAWC's or Staff's assessments of the proposal in its rebuttal testimony or briefs and it failed to provide any legal argument in its briefs to support its proposal. Notably, the AG has not presented evidence to demonstrate that its proposal is needed in this proceeding. It also appears that applying the limitation to non-residential classes, including those served under contracts that set their rates, may be problematic. Further, it also appears that many of the customer classes would experience more significant rate increases under the AG's proposal than they would under the Company's proposal. Accordingly, the Commission adopts the Company's proposed percentage increases by class as specified on page two of IAWC Exhibit 11.01R, which will be adjusted based on the Company's final revenue requirement.

6. Demand Factors

a. IAWC's Position

IAWC states that consistent with the Commission's directives in Docket No. 110767, the Company conducted a direct measurement demand study in preparation for this case, in which the Company directly measured the demand of a sample group of customers between May 2011 and October 2015. *See* Docket No. 11-0767, Order at 113-114. IAWC used the results of that demand study to develop the demand factors it proposes in this case. IAWC Ex. 11.00R at 3. IAWC notes that Staff and AG witnesses accepted the proposed demand factors, but IIWC/FEA witness Collins recommended that the Commission ignore the results of the demand study, and rely instead on demand factors developed and approved in IAWC's last rate case in Docket No. 11-0767. IIWC/FEA Ex. 1.0 at 15. IAWC notes that IIWC/FEA also recommend that the Commission order the Company to continue its demand study. IAWC argues that the Commission should reject Mr. Collins' proposal and approve the updated demand factors the Company proposes here, and which Staff and the AG support.

***91** IAWC asserts that its proposed demand factors reflect the most recent available actual data regarding its customers' demand. IAWC Ex. 11.00R at 3. In contrast, IAWC notes that the demand factors Mr. Collins advocates are based on very limited direct measurement data collected prior to the filing of IAWC's rate case in 2011. *Id.* In the years since Docket No. 11-0767, IAWC states that it has collected more comprehensive data, and its proposed demand factors are based on that more recent, more comprehensive data. *Id.*

The Company contends that the Commission has expressed a preference for demand factors based on the most recent available data. *See, e.g.*, Docket No. 09-0319, Order at 149-150; Docket No. 07-0507, Order at 121; Docket No. 02-0690, Order at 119-120. Additionally, IAWC argues that Mr. Collins has not offered a compelling reason to reject the Company's more recent, more comprehensive data, or to reconsider the Commission's preference for more recent data. Tellingly, IAWC points out, Mr. Collins did not respond in testimony to IAWC's criticisms of his proposal. *See* IIWC/FEA Ex. 2.0 at 4-7.

IAWC takes issue with IIWC/FEA's argument that IAWC has failed to provide any evidence to explain why the demand factors for some customer classes differ from those adopted in IAWC's last rate case. The Company reiterates that its proposed demand factors reflect the most recent available data about customers' actual demand. Therefore, IAWC maintains, there is no need to provide evidence explaining why the demand factors have changed. Nevertheless, IAWC notes that its witness Mr. Herbert explained that the demand factors differ because the data used to calculate the demand factors in preparation for Docket No. 11-0767 was much more limited in scope than the data collected for this case. IAWC Ex. 11.00R at 3. IAWC argues that IIWC/FEA's proposal would require IAWC to rely on the obsolete data, simply because the results of the recent, lengthy, and in-depth study differ from the older and more cursory data collection efforts.

IAWC states that the Commission should also reject IIWC/FEA's request that the Company be ordered to continue its demand study. IAWC notes that IIWC/FEA argue, for the first time in their briefs, that they do not believe the demand study is complete and therefore the Company should continue to monitor the situation. IAWC argues that all of the record evidence shows that an ongoing demand study is not cost-effective and is unnecessary. IAWC elaborates that IIWC/FEA did not offer testimony that the demand study should be continued. However, IAWC states that every other party that offered testimony on the subject — Staff, the AG, and IAWC — agreed that IAWC's demand study will be valid for ten years, and that it is not cost-effective to continue the demand study. IAWC Ex. 11.00R at 3; Staff Ex. 6.0 at 35-36; AG Ex. 2.0 at 16.

***92** Further, IAWC explains that the Company and Staff agreed that the Company should only conduct a demand study once every ten years, and the Company should use the less resource intensive AWWA-method rather than direct measurement. IAWC Ex. 11.00R at 3-4. IAWC contends that IIWC/FEA's assertion that the Company should continue to monitor the situation ignores IAWC's agreement with Staff to conduct AWWA-method demand studies once every ten years and submit evidence in future rate cases that there has not been a significant change in the ratio of peak to average demand. Staff Ex. 6.0 at 36; IAWC Ex. 11.00R at 4.

b. Staff's Position

It is Staff's position that the Commission should reject IIWC/FEA's proposal to use the demand factors that were approved in the Company's last rate case and its proposal that the Company continue its demand study.

Staff notes that IIWC/FEA assert that they are concerned that the Company's proposed demand factors are flawed and used inappropriately in the COSS. IIWC/FEA Ex. 1.0 at 15. They contend that the Company has excluded a large industrial user and an entire rate class from the COSS and that the Company understated usage for its Residential and Commercial classes in the COSS. *Id.* Staff also notes that IAWC states that the demand study that it conducted in preparation for this case is the result of collecting direct measurement data over the most recent five year period. IAWC Ex. 11.00R at 3. IAWC further states that the demand factors used in Docket No. 11-0767 included very little direct measurement data and all of it is now outdated because that study reflected data leading up to the filing of the rate case in 2011. *Id.*

Like IAWC, Staff contends that IIWC/FEA have failed to provide a convincing argument to support their recommendation to use outdated demand data when more recent, direct, and comprehensive data is available. Staff Ex. 14.0 at 12. Staff asserts that it agrees that IAWC's demand study will be valid for ten years. Thus, Staff submits that the Commission should reject IIWC/FEA's recommendation that IAWC continue its demand study. Staff explains that its witness Mr. Boggs testified that IAWC should be allowed to conduct a AWWA-method demand study every ten years and submit evidence in future rate cases that there has not been a significant change in the ratio of peak to average demand. Staff Ex. 6.0 at 36. Therefore, Staff recommends that the Commission approve the Company's proposed direct demand study data and that it allow the Company to conduct AWWA-method demand studies once every ten years provided that the Company submits evidence in future rate cases that there has not been a significant change in the ratio of peak to average demand.

c. AG's Position

AG witness Rubin testified that the Company should not be required to continue its demand study. Mr. Rubin opined that it is not cost-effective for the Company to continue collecting individual customer demand data for study purposes. AG Ex. 2.0 at 16. He agreed with Staff and IAWC that the demand study provided in this case can be used for many years in the future, therefore he concluded that there is no need to conduct such a study for each rate case. *Id.*

d. IIWC/FEA's Position

***93** IIWC/FEA state that they believe the demand study the Company conducted in preparation for this case is incomplete, and they recommend that the Company continue to monitor the situation. IIWC/FEA Ex. 1.0 at 14. IIWC/FEA argue that the Company has mischaracterized their opposition to ending the monitoring as ignoring the results of the study IAWC prepared for this case. IAWC Ex. 11.00R at 2. IIWC/FEA claim that they recommend that monitoring continue due to some significant changes in the demand factors since the last IAWC rate case. IIWC/FEA explain that a comparison of the demand factors for Zone 1 from this case with those used in the last case indicate that some classes' factors have significantly changed. IIWC/FEA Ex. 1.0 at 14. IIWC/FEA note that they presented this comparison in IIWC/FEA Exhibit 1.2.

IIWC/FEA also argue that the Company failed to provide any evidence as to why certain classes would see such a change in demand ratios between rate cases and they failed to adequately explain why this has occurred. *Id.* IIWC/FEA state that they are not attempting to ignore the results of the Company's study but rather they are using the collected information to show that continued monitoring is necessary. Additionally, IIWC/FEA acknowledge that the Company has incurred significant costs to conduct the study, but they claim the cost to certain customer classes, in the form of interclass subsidies, will likely be much more expensive if the demand factors are incorrect.

IIWC/FEA indicate that the Company has addressed some of the concerns they raised in this proceeding, due to the significant changes in some classes' demand factors, however, IIWC/FEA remain concerned that the Company's proposed demand factors are flawed and inappropriate for use in the COSS. IIWC/FEA argue that the use of flawed factors will not result in appropriate cost allocation to classes. As a result, IIWC/FEA recommend that the Company use the existing demand factors approved in the last rate case for Zone 1 and that it continue to monitor the situation. IIWC/FEA Ex. 1.0 at 14-15.

e. Commission Analysis and Conclusion

The Commission notes that IIWC/FEA question whether the demand study prepared by the Company in preparation for this proceeding is complete. They believe the Company has not sufficiently explained the difference between the demand factors for some customer classes in IAWC's last rate case and the demand factors it proposes in this proceeding. Due to these perceived shortcomings, IIWC/FEA recommend that the Company use the existing demand factors approved in the last rate case for Zone 1 instead and that the Company continue its direct demand study.

Staff, the AG, and the Company agree that the Commission should approve the use of IAWC's proposed demand factors and permit the Company to discontinue its demand study. Staff and IAWC agree that the Company should be allowed to conduct AWWA-method demand studies every ten years, provided that the Company submits evidence in future rate cases that there has not been a significant change in the ratio of peak to average demand. The AG agrees that the current demand study can be used for some time and that it is unnecessary for the Company to conduct a demand study for each rate case.

***94** The Commission concurs with Staff and IAWC. The Company complied with the Commission's prior directive in Docket No. 11-0767 by conducting a direct demand study in preparation for this case and using the collected data to develop the Company's proposed demand factors. The Company's proposed demand factors reflect the most recent and comprehensive available data concerning its customers' demand. IAWC explains that there is a difference between the demand factors proposed in this case and in the Company's last rate case because the direct demand study measures customers' actual demand over the most recent five year period and the data used to calculate the demand factors in the Company's last rate case was more limited in scope than the data collected in preparation for this proceeding. Moreover, as stated by Staff and the Company, IIWC/FEA failed to provide a compelling reason to support the use of demand factors based on older data instead of the most recent and comprehensive data available. Finally, the record supports Staff's and IAWC's position that the Company should be allowed to conduct AWWA-method demand studies every ten years. Staff, the AG, and IAWC all agree that the Company's current demand study will be valid for ten years and that direct measurement demand studies are resource-intensive, unlike the AWWA-method which is more commonly used for determining demand factors.

Accordingly, the Commission rejects IIWC/FEA's proposal and adopts the Company's proposed demand factors. The Commission also adopts the proposal by Staff and IAWC that the Company only conduct a demand study using the AWWA-method once every ten years, and submit evidence in future rate cases indicating that there has not been a significant change in the ratio of peak to average demand.

VII. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record herein and being fully advised in the premises, is of the opinion and finds that:
(1) IAWC is in the business of furnishing water and sewer service to the public in various areas in the State of Illinois and is a public utility as defined in the Act;

(2) the Commission has jurisdiction over the parties hereto and of the subject matter herein;

(3) the findings and conclusions stated in the prefatory portion of this Order are supported by the evidence of record and are hereby adopted as findings of fact; Appendices A through E attached hereto provide supporting calculations for various conclusions in this Order;

(4) the test year in this proceeding is a future test year consisting of the 12 months ending December 31, 2017; this test year is appropriate for purposes of this proceeding;

(5) for purposes of this proceeding, IAWC's net original cost rate bases are set forth in Appendices A through E;

(6) the $1,570,415,946 original cost of plant for IAWC at September 30, 2015, as presented in Staff Exhibit 2.0, should be approved as the original cost of plant;

***95** (7) a just and reasonable rate of return which IAWC should be allowed an opportunity to earn on its net original cost rate base is 7.47%; this rate of return incorporates an ROE of 9.79%;

(8) the rates of return set forth in Finding (7) hereinabove result in operating revenues and net annual operating income as shown in Appendices A through E based on the test year herein approved;

(9) IAWC's rates which are presently in effect for water service and sewer service are insufficient to generate the operating income necessary to permit it the opportunity to earn a fair and reasonable return on net original cost rate base; the currently effective rates should be permanently canceled and annulled;

(10) the rates proposed by IAWC would produce a rate of return in excess of a return that is fair and reasonable; IAWC's Proposed Tariffs should be permanently canceled and annulled;

(11) IAWC should be authorized to place into effect tariff sheets designed to produce annual operating revenues as contained in Appendices A through E, such tariff sheets to be applicable to service furnished on and after their effective date; the terms and conditions in these tariff sheets should be consistent with Finding (13) below;

(12) the cost of service, interclass revenue allocation, rate design, and tariff terms and conditions found appropriate in the prefatory portion of this Order are just and reasonable for purposes of this proceeding and should be adopted; and

(13) the new tariff sheets authorized to be filed by this Order shall reflect an effective date not less than five working days after the date of filing, with the tariff sheets to be corrected within that time period if necessary, except as is otherwise required by Section 9-201(b) of the Act as amended.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the Proposed Tariffs proposing a general increase in rates, filed by Illinois-American Water Company on January 21, 2016, are hereby permanently canceled and annulled.

IT IS FURTHER ORDERED that Illinois-American Water Company is authorized and directed to file new tariff sheets with supporting workpapers in accordance with Findings (11), (12), and (13) of, and other determinations in, this Order, applicable to service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that upon the effective date of the new tariff sheets to be filed pursuant to this Order, the tariff sheets presently in effect for water and sewer service rendered by Illinois-American Water Company which are replaced thereby are hereby permanently canceled and annulled.

IT IS FURTHER ORDERED that the $1,570,415,946 original cost of plant for Illinois-American Water Company at September 30, 2015, as presented in Staff Exhibit 2.0, is approved as the original cost of plant.

IT IS FURTHER ORDERED that all motions, petitions, and objections which have not been disposed of are hereby deemed to be disposed of in a manner consistent with the conclusions herein.

***96** IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By Order of the Commission this 13th day of December, 2016.

Footnotes

1 IAWC explained that "Revenue Requirement" support is Service Company personnel assistance in preparing revenue requirements, testimonies and exhibits, data request responses, analyses, as necessary, and final tariffs. It also includes the expense for Service Company personnel to attend hearings. IAWC Ex. 4.00.

2 Schedule C-10 also shows IAWC's projected $250,000 "Internal Demand Study Costs." IAWC explained that this represents the costs for utility personnel to continue the data collection and analysis required for the Demand Study the Commission ordered in Docket No. 11-0767, through final resolution of this case. IAWC-AG Stip. Cross Ex. 2.00 at 6; IAWC Ex. 15.03SR at 11, 33, 63. Schedule C-10 also includes $200,000 in "Other" costs for customer communications related to the rate case, $110,000 of which IAWC explains it had incurred at the time of its surrebuttal filing. IAWC-AG Stip. Cross Ex. 2.00 at 6; IAWC Ex. 4.00SR at 14; IAWC Ex. 4.11SR.

3 See IAWC Initial Brief at 2-3; IAWC Reply Brief at 1-4; IAWC Ex. 10.00R at 2-5; see also Docket Nos.: 14-0419; 11-0436; 11-0767; 10-0194; 09-0319; 07-0507; 06-0285; 05-0071/72; 04-0442; 03-0403; 00-0340.

End of Document

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of the Laclede Gas Company's Request to Increase Its Revenues for Gas Service	)))	**File No. GR-2017-0215** Tariff No. YG-2017-0195
In the Matter of the Laclede Gas Company d/b/a Missouri Gas Energy's Request to Increase Its Revenues for Gas Service	)))	**File No. GR-2017-0216** Tariff No. YG-2017-0196

REPORT AND ORDER

Issue Date: February 21, 2018

Effective Date: March 3, 2018

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of the Laclede Gas Company's Request to Increase Its Revenues for Gas Service	)))	**File No. GR-2017-0215** Tariff No. YG-2017-0195
In the Matter of the Laclede Gas Company d/b/a Missouri Gas Energy's Request to Increase Its Revenues for Gas Service	)))	**File No. GR-2017-0216** Tariff No. YG-2017-0196

Table of Contents

APPEARANCES

Rick Zucker, **Michael C. Pendergast**, **Larry W. Dority**, and **James M. Fischer**, Attorneys at Law, 700 Market Street, Sixth Floor, St. Louis, Missouri 63101

For Spire Missouri Inc.

Brian T. Bear, General Counsel, 301 W. High Street, Room 680, Jefferson City, Missouri 65102

For the Missouri Division of Energy.

Andrew J. Linhares, Staff Attorney, 409 Vandiver Drive, Building 5, Suite 205, Columbia, Missouri 65202

For the National Housing Trust.

Natalie Karas, Senior Regulatory Attorney, 1875 Connecticut Avenue NW, Washington, DC 20009

For the Environmental Defense Fund.

David Woodsmall, Attorney at Law, 308 E. High Street, Suite 204, Jefferson City, Missouri 65101

For the Midwest Energy Consumers Group.

Lewis Mills and **Edward F. Downey**, Attorneys at Law, 221 Bolivar Street, Suite 101, Jefferson City, Missouri 65101.

For the Missouri Industrial Energy Consumers.

John B. Coffman, Attorney at Law, 871 Tuxedo Boulevard, St. Louis, Missouri 63119

For the Consumers Council of Missouri.

William D. Steinmeier, Attorney at Law, 2031 Tower Drive, Jefferson City, Missouri 65110

For the City of St. Joseph, Missouri.

Terry M. Jarrett, Attorney at Law, 514 E. High Street, Suite 22, Jefferson City, Missouri 65101

For MoGas Pipeline, LLC.

Richard S. Brownlee, III, Attorney at Law, 121 Madison, Jefferson City, Missouri 65101

For the Missouri School Boards' Association.

Lera Shemwell, Legal Counsel, **Ryan Smith**, Legal Counsel, **Nathan Williams**, Deputy Staff Counsel, and **Hampton Williams**, Legal Counsel, 200 Madison Street, Suite 650, Jefferson City, Missouri 65102

For the Office of the Public Counsel.

Whitney Payne, Associate Counsel, **Mark Johnson**, Senior Counsel, **Casi Aslin**, Legal Counsel, **Marcella Forck**, Associate Counsel, **Nicole Mers,** Deputy Counsel, **Jeff Keevil**, Deputy Counsel, and **Kevin Thompson**, Chief Staff Counsel, 200 Madison Street, Suite 800, Jefferson City, Missouri 65102

For the Staff of the Missouri Public Service Commission.

SENIOR REGULATORY LAW JUDGE: Nancy Dippell

The Missouri Public Service Commission, having considered all the competent and substantial evidence upon the whole record, makes the following findings of fact and conclusions of law. The positions and arguments of all of the parties have been considered by the Commission in making this decision. Failure to specifically address a piece of evidence, position, or argument of any party does not indicate the Commission has failed to consider relevant evidence, but indicates rather that the omitted material was not dispositive of this decision.

Procedural History

On April 11, 2017, Spire Missouri Inc., then known as Laclede Gas Company, and referred to herein as "Spire Missouri,"[1] filed tariffs designed to implement general rate increases for gas service in its Spire Missouri East (f/k/a Laclede Gas Company, and referred to herein as "LAC" or "Laclede") and Spire Missouri West (f/k/a Missouri Gas Energy and referred to herein as "MGE") territories. The tariffs would have increased Laclede's annual gas revenues by approximately $58.1 million, exclusive of associated taxes, of which approximately $29.5 million is already being recovered through its infrastructure system replacement surcharge (ISRS), resulting in a net increase of $28.5 million.[2] The tariffs would have increased MGE's annual gas revenues by approximately $50.4 million, exclusive of associated taxes, of which approximately $13.4 million is already being recovered through its ISRS, resulting in a net increase of $37.0 million.[3] The tariff revisions carried an effective date of May 11, 2017.

By orders issued on April 19, 2017, the Commission suspended Spire Missouri's general rate increase tariffs until March 8, 2018, the maximum amount of time allowed by the controlling statute.[4] The following parties filed applications and were allowed to intervene: Missouri Industrial Energy Consumers (MIEC); Midwest Energy Consumers Group (MECG); Missouri Department of Economic Development – Division of Energy (DE); Consumers Council of Missouri (Consumers Council); Missouri School Boards'

---

[1] This is the first general rate case the Commission has heard since Laclede Gas Company acquired Missouri Gas Energy on July 17, 2013. During the course of this proceeding, on August 30, 2017, Laclede Gas Company changed its name to Spire Missouri Inc. and now operates its two divisions in Missouri as Spire Missouri East and Spire Missouri West.
[2] File No. GR-2017-0215, In the Matter of Laclede Gas Company Request to Increase Its Revenues for Gas Service, Tariff No. YG-2017-0195, filed April 11, 2017.
[3] File No. GR-2017-0216, In the Matter of Laclede Gas Company d/b/a Missouri Gas Energy's Request to Increase Its Revenues for Gas Service, Tariff No. YG-2017-0196, filed April 11, 2017.
[4] Section 393.150, RSMo 2016. (All statutory references are to the Revised Statutes of Missouri 2016, unless otherwise noted.)

Association; The City of St. Joseph, Missouri; National Housing Trust; Environmental Defense Fund; MoGas Pipeline, LLC; USW Local 11-6; Kansas City Power and Light Company; and KCP&L Greater Missouri Operations.[5] On May 24, 2017, the Commission established the test year for these cases as the 12-month period ending December 31, 2016, to be updated for known and measurable changes through June 30, 2017 and trued-up for known and measurable revenue, rate base, and expense items through September 30, 2017. In its May 24, 2017 orders, the Commission also established a procedural schedule leading to an evidentiary hearing. The cases were consolidated for hearing purposes, but remain separate cases with similar filings.

In September and October 2017, the Commission conducted eleven local public hearings at various sites[6] in Laclede's and MGE's service areas. At those hearings, the Commission heard comments from Spire Missouri's customers and the public regarding the requests for rate increases.

In compliance with the established procedural schedule, the parties prefiled direct, rebuttal, and surrebuttal testimony and direct and rebuttal true-up testimony. The evidentiary hearing began on December 6, 2017, and concluded on December 15, 2017. The true-up hearing was held on January 3, 2018. The parties filed post-hearing briefs on January 9, 2018, and reply briefs on January 17, 2018.

On January 18, 2018, the Commission directed Spire Missouri to submit an affidavit explaining the specific adjustments that would be needed to include in rates

[5] The USW Local 11-6 intervened only in File No. GR-2017-0215 and Kansas City Power and Light Company and KCP&L Greater Missouri Operations intervened only in File No. GR-2017-0216.
[6] Hearings were held in Joplin, Independence, St. Joseph, Arnold, St. Louis, Sunset Hills, St. Charles, Kansas City, and Gladstone, Missouri.

any change in cost of service as a result of the Tax Cuts and Jobs Act[7] for each of Spire Missouri's operating units. The Commission also set a date for requests for a hearing on the issues and indicated that if a hearing were set it would be held on February 5, 2018. Spire Missouri filed an affidavit of Glenn Buck on January 22, 2018, and on January 25, 2018, Staff filed an affidavit in reply. On January 26, 2018, the Commission set a technical conference for January 30, 2018 and set a hearing on February 5, 2018. A hearing was held on February 5, 2018 and written closing statements were filed on February 6, 2018.

Complaint Case

In addition to the above procedures, on April 27, 2016, the Office of the Public Counsel (OPC) filed a complaint with the Missouri Public Service Commission against Spire Missouri assigned File No. GC-2016-0297. The complaint alleged that Spire Missouri's rates were excessive and should be reduced. On October 5, 2016, the Commission granted *OPC's Motion to Stay Proceedings*. On July 31, 2017, OPC filed a *Motion to Lift Stay and Consolidate with the Companies' Current Rate Cases*. The Commission granted that motion and on August 11, 2017, consolidated the complaint case with the two pending rate cases.

After hearing the evidence in this matter, the Commission finds there is insufficient evidence to establish that LAC or MGE have earned an actual return on equity that is significantly higher than necessary to attract necessary capital, to provide safe and reliable service, or significantly higher than commensurate returns by enterprises having corresponding risks indicating that their ordered rates were not just

[7] Public Law No.: 115-97; signed into law on December 22, 2017.

and reasonable. Therefore, the Commission denies Public Counsel's complaint. The Commission further notes, however, that in this order it has determined just and reasonable rates on a going forward basis.

The Partial Stipulations and Agreements

On October 25, 2017, the Commission approved the *Joint Stipulation and Agreement* between the Missouri School Boards' Association and Spire Missouri which settled all issues between those parties.[8] During the course of the evidentiary hearing, various parties filed three additional non-unanimous partial stipulations and agreements: *Partial Stipulation and Agreement*;[9] *Partial Non-Unanimous Stipulation and Agreement;*[10] and *Non-Unanimous Stipulation Regarding Revenue Allocation and Non-Residential Rate Design*.[11] Those stipulations and agreements resolved issues that would otherwise have been the subject of testimony at the hearing. After the hearing, an additional non-unanimous *Partial Stipulation and Agreement Regarding Low Income Energy Affordability Program* was filed.[12] No party opposed those partial stipulations and agreements. As permitted by its regulations, the Commission treats the unopposed partial stipulations and agreements as unanimous.[13]

After considering these stipulations and agreements, the Commission independently finds and concludes that the stipulations and agreements are reasonable resolutions of the issues addressed by those agreements. The Commission further finds

[8] *Order Approving Joint Stipulation and Agreement Regarding Spire West's (Formerly Known as Missouri Gas Energy) STP Tariff*, issued October 25, 2017.
[9] Filed December 13, 2017.
[10] Filed December 20, 2017.
[11] Filed December 20, 2017.
[12] Filed January 9, 2018.
[13] Commission Rule 4 CSR 240-2.115(C).

and concludes that those agreements should be approved. The issues resolved in those stipulations and agreements will not be further addressed in this report and order, except as they may relate to any unresolved issues.

Just prior to the hearing on February 5, 2018, Public Counsel, MIEC, MECG, and Consumers Council filed a *Non-Unanimous Stipulation and Agreement Regarding Tax Cuts and Jobs Act*. Spire Missouri made an oral objection to the agreement at the hearing. Thus, under 4 CSR 240-2.115(D), that stipulation and agreement became "merely a position of the signatory parties" thereto.

General Findings of Fact and Conclusions of Law

Spire Missouri set out its rationale for increasing its rates in the direct testimony it filed along with its tariffs on April 11, 2017.[14] In addition to its filed testimony, Spire Missouri provided work papers and other detailed information and records to the Staff of the Commission, Public Counsel, and to the intervening parties. Those parties then had the opportunity to review Spire Missouri's testimony and records to determine whether the requested rate increase was justified.

Where the parties disagreed, they prefiled written testimony to raise those issues to the attention of the Commission. All parties were given an opportunity to prefile three rounds of testimony – direct, rebuttal, and surrebuttal. The process of filing testimony and responding to the testimony filed by other parties revealed areas of agreement that resolved some issues and areas of disagreement that revealed new issues. On December 1, 2017, the parties filed a list of the issues they asked the Commission to

[14] Exhibit Nos. 1-4, 6, 10, 15, 19, 23, 28, 33, 35, 38, 46, and 50.

resolve. Some of the issues identified at that time were later resolved by the stipulations and agreements or otherwise by agreement at hearing. On December 29, 2017, the parties filed a further list of issues for Commission resolution at the true-up hearing. On January 1, 2018, the Commission additionally requested testimony and comment regarding the Tax Cuts and Jobs Act. Additional testimony was taken on February 5, 2017 on that issue. The unresolved issues will be addressed in this report and order.

General Findings of Fact

1. Spire Missouri is an investor-owned gas utility providing retail gas service to large portions of Missouri through its two operating units or divisions, Spire Missouri East (formerly known as Laclede Gas Company or LAC) and Spire Missouri West (formerly known as Missouri Gas Energy or MGE).

2. Spire Missouri is a wholly-owned subsidiary of Spire Inc.[15] In 2016, Spire Inc. had three gas distribution systems as wholly-owned subsidiaries including Laclede Gas Company in Missouri, Alabama Gas Corporation (Alagasco) in Alabama, and EnergySouth Inc. in Alabama and Mississippi.[16] Spire Inc. also holds gas marketing business segments and Spire STL Pipeline LLC, a company applying for permits at the Federal Energy Regulatory Commission (FERC) to build a pipeline.[17]

3. MGE serves approximately 500,000 customers on the western side of Missouri. The Commission approved the acquisition of MGE by Laclede Gas Company

[15] Ex. 205, Staff Report - Cost of Service, p. 17.
[16] Ex. 205, Staff Report - Cost of Service, p. 17-18.
[17] Ex. 205, Staff Report - Cost of Service, p. 18; and Ex. 650, Lander Direct, p. 12.

when it approved a *Unanimous Stipulation and Agreement* dated July 2, 2013, in Commission Case No. GM-2013-0254.[18]

4. The Commission last authorized a general rate increase for MGE on April 16, 2014, in Case No. GR-2014-0007, with new rates effective on May 1, 2014. That case was settled by a stipulation and agreement approved by the Commission that increased MGE's Missouri jurisdictional revenues by $7.8 million and reset the ISRS to zero.[19]

5. LAC serves approximately 630,000 customers on the eastern side of Missouri.

6. The Commission last authorized a general rate increase for LAC on June 26, 2013, in Case No. GR-2013-0171, with new rates effective July 8, 2013. That case was also settled by a stipulation and agreement approved by the Commission and reset the ISRS rate to zero.[20]

7. A test year is a historical year used as the starting point for determining the basis for adjustments that are necessary to reflect annual revenues and operating costs in calculating any shortfall or excess of earnings by the utility. Adjustments, such as annualization and normalization, are made to the test year results when the unadjusted results do not fairly represent the utility's most current annual level of existing revenue and operating costs.[21]

8. A normalization adjustment is an adjustment made to reflect normal, on-going operations of the utility. Revenues or costs that were incurred in the test year that

[18] Ex. 205, Staff Report - Cost of Service, p. 3; and Ex. 55, Stipulation and Agreement in Case No. GM-2013-0254.
[19] Exhibit 204, Staff Cost of Service Report dated September 2017, p. 3.
[20] Exhibit 204, Staff Cost of Service Report dated September 2017, p. 3.
[21] Ex. 205, Staff Report - Cost of Service, p. 3.

are determined to be atypical or abnormal will get specific rate treatment and generally require some type of adjustment to reflect normal or typical operations. The normalization process removes abnormal or unusual events from the cost of service calculations and replaces those events with normal levels of revenues or costs.

9. An annualization adjustment is made to a cost or revenue shown on the utility's books to reflect a full year's impact of that cost or revenue.[22]

10. The test year for this case is the twelve months ending December 31, 2016, updated to June 30, 2017.[23]

11. The Commission also ordered a true-up period ending September 30, 2017, in order to account for any significant changes in Spire Missouri's cost of service that occurred after the end of the test year period but prior to the tariff operation of law date.[24]

> 12. For ratemaking purposes, a tracker mechanism is a unique regulatory tool used to ensure that rate recovery over time is made equal to the actual expenditures for a particular cost of service item. A tracker mechanism compares the ongoing amount of a cash expense actually incurred by a utility to the amount of the same expense reflected in the utility's rates, and provides rate recovery over time of the difference between the two totals. Generally, tracker mechanisms should only be used for certain cost items incurred by utilities that show unusual characteristics or are incurred under extraordinary circumstances. . . . Ongoing tracker mechanisms capture both under and over recovery of an expense for recovery from or return to ratepayers.
>
> The overall goal of a tracker mechanism, when properly exercised, is to provide the utility with dollar for dollar recovery of reasonable and prudently incurred cash expenses, but no more and no less than dollar for dollar recovery.[25]

13. The Commission finds that any given witness' qualifications and overall

[22] Ex. 205, Staff Report - Cost of Service, p. 97.
[23] Ex. 205, Staff Report - Cost of Service, p. 4.
[24] Ex. 205, p. 4.
[25] Ex. 205, Staff Report - Cost of Service, p. 64

credibility are not dispositive as to each and every portion of that witness' testimony. The Commission gives each item or portion of a witness' testimony individual weight based upon the detail, depth, knowledge, expertise, and credibility demonstrated with regard to that specific testimony. Consequently, the Commission will make additional specific weight and credibility decisions throughout this order as to specific items of testimony as is necessary.[26]

14. Any finding of fact reflecting that the Commission has made a determination between conflicting evidence is indicative that the Commission attributed greater weight to that evidence and found the source of that evidence more credible and more persuasive than that of the conflicting evidence.[27]

The Rate Making Process

15. The rates Spire Missouri will be allowed to charge its customers are based on a determination of the company's revenue requirement. The revenue requirement can be expressed as the following formula:[28]

$$\mathbf{RR = COS - CR}$$

where: **RR = Revenue Requirement**
COS = Cost of Service
CR = Adjusted Current Revenues

The cost-of-service for a regulated utility can be defined by the following formula:

$$\mathbf{COS = O + (V - D)R}$$

[26] Witness credibility is solely a matter for the fact-finder, "which is free to believe none, part, or all of the testimony". *State ex rel. Public Counsel v. Missouri Public Service Comm'n*, 289 S.W.3d 240, 247 (Mo. App. 2009).
[27] An administrative agency, as fact finder, also receives deference when choosing between conflicting evidence. *State ex rel. Missouri Office of Public Counsel v. Public Service Comm'n of State*, 293 S.W.3d 63, 80 (Mo. App. 2009).
[28] Ex. 201, Myers Direct, pp. 6-7.

where: **COS = Cost of Service;**
O = Adjusted Operating Costs (Payroll, Maintenance, etc.), Depreciation Expense and Taxes
V = Gross Valuation of Property Required for Providing Service
D = Accumulated Depreciation Representing Recovery of Gross Property Investment
R = Allowed Rate of Return
V – D = Rate Base (Gross Property Investment less Accumulated Depreciation = Net Property Investment)
(V - D)R = Return Allowed on Net Property Investment

All parties accept the basic formula. Disagreements arise over the amounts that should be included in the formula.

Conclusions of Law Regarding Jurisdiction

A. Spire Missouri is a public utility, and a gas corporation, as those terms are defined in Subsections 386.020(18) and (43), RSMo. As such, Spire Missouri is subject to the Commission's jurisdiction pursuant to Chapters 386 and 393, RSMo.

B. Spire Missouri can charge only those amounts set forth in its tariffs.[29] Subsection 393.140(11), RSMo, gives the Commission authority to regulate the rates Spire Missouri may charge its customers for natural gas.

C. When Spire Missouri filed a tariff designed to increase its rates, the Commission exercised its authority under Section 393.150, RSMo, to suspend the effective date of that tariff for 120 days beyond the effective date of the tariff, plus an additional six months.

D. Sections 386.390 and 393.150, RSMo, authorize the Commission to determine complaints, including those regarding regulated utility rates.

[29] Sections 393.130 and 393.140, RSMo.

Conclusions of Law Regarding Just and Reasonable Rates

A. Utilities are required to provide safe and adequate service.[30] In determining the rates Spire Missouri may charge its customers, the Commission is required to determine that the proposed rates are just and reasonable.[31]

B. Spire Missouri has the burden of proving its proposed rates are just and reasonable.[32] In order to carry its burden of proof, Spire Missouri must meet the preponderance of the evidence standard.[33] In order to meet this standard, Spire Missouri must convince the Commission it is "more likely than not" that Spire Missouri's proposed rate increase is just and reasonable.[34]

C. In determining whether the rates proposed by Spire Missouri are just and reasonable, the Commission must balance the interests of the investor and the consumer.[35] In discussing the need for a regulatory body to institute just and reasonable rates, the United States Supreme Court has held as follows:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[36]

In the same case, the Supreme Court provided the following guidance on what is a just and reasonable rate:

---

[30] Sections 393.130 and 393.140, RSMo.
[31] Section 393.150.2, RSMo.
[32] Section 393.150.2, RSMo.
[33] *Bonney v. Environmental Engineering, Inc.*, 224 S.W.3d 109, 120 (Mo. App. 2007); *State ex rel. Amrine v. Roper*, 102 S.W.3d 541, 548 (Mo. banc 2003); *Rodriguez v. Suzuki Motor Corp.*, 936 S.W.2d 104, 110 (Mo. banc 1996), citing to, *Addington v. Texas*, 441 U.S. 418, 423, 99 S.Ct. 1804, 1808, 60 L.Ed.2d 323, 329 (1979).
[34] *Holt v. Director of Revenue, State of Mo*., 3 S.W.3d 427, 430 (Mo. App. 1999); *McNear v. Rhoades*, 992 S.W.2d 877, 885 (Mo. App. 1999); *Rodriguez v. Suzuki Motor Corp*., 936 S.W.2d 104, 109-111 (Mo. banc 1996); *Wollen v. DePaul Health Center*, 828 S.W.2d 681, 685 (Mo. banc 1992).
[35] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603, (1944).
[36] *Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 690 (1923).

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[37]

The Supreme Court has further indicated:

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[38]

D. In undertaking the balancing required by the Constitution, the Commission is not bound to apply any particular formula or combination of formulas. Instead, the Supreme Court has said:

> Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.[39]

[37] *Bluefield,* at 692-93.
[38] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (citations omitted).
[39] *Federal Power Commission v. Natural Gas Pipeline Co*. 315 U.S. 575, 586 (1942).

E. Furthermore, in quoting the United States Supreme Court in *Hope Natural Gas*, the Missouri Court of Appeals said:

> [T]he Commission [is] not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' … Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed which is controlling. It is not theory but the impact of the rate order which counts.[40]

Issues

The issues are set out as the parties phrased them, but have been renumbered and reorganized herein.

I. Forest Park Property

A. **How should any gain resulting from the sale of the Forest Park property be treated for ratemaking purposes?**

B. **How should the relocation proceeds from the sale of the Forest Park property, other than proceeds used for relocation purposes or contributed to capital for the benefit of customers, be treated for ratemaking purposes?**

Findings of Fact

1. LAC owned and operated three large district service centers for several decades. These service centers provided leak detection, leak repair, construction, maintenance, marketing, and other services for the company. One of these service centers was located near Forest Park in the City of St. Louis (referred to as the "Forest Park property").[41] The Forest Park property provided some functions, such as gas procurement, gas controls, and diversion services that were not provided at the other

[40] *State ex rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n*, 706 S.W. 2d 870, 873 (Mo. App. W.D. 1985).
[41] Ex. 205, Staff Cost of Service Report, p. 48.

two service centers.[42]

2. After Laclede Gas Company purchased Missouri Gas Energy, certain restructuring of the company was undertaken. The major elements of the restructuring in the St. Louis area for LAC included: (a) the 2014 sale of the Forest Park property; (b) the 2015 termination of the lease for the Laclede Gas Company main corporate office at 720 Olive Street; (c) the 2015 leasing of new office facilities at 700 and 800 Market Street; and (d) and the 2016 construction of a new satellite operation facility on Manchester Avenue.[43]

3. In order to provide additional negotiation leverage for potential sale of the Forest Park property, LAC acquired two parcels in January 2013 that were adjacent to the Forest Park service center for $450,000 plus some additional expenses.[44] These properties were included in the Forest Park property sale.

4. On June 27, 2013, LAC signed an agreement to sell the Forest Park property to The Cortex Innovation Community in St. Louis (Cortex). Cortex, an urban redevelopment corporation, purchased the property for an IKEA retail store now located on the property.[45]

5. Cortex obtained an appraisal of the property for the purpose of determining the property value for redevelopment by a specific retail business. That appraisal found the market value for the property with all of the buildings and structures was $6.89 million. The appraised market value for the property with all the buildings

[42] Ex. 205, Staff Cost of Service Report, p. 48.
[43] Ex. 42, Kopp Rebuttal, p. 4.
[44] Ex. 250, Kunst Surrebuttal, Schedule JK-s1, p.2 (the specific "other expenses" were designated as "Confidential" in Staff's schedule and will not be denominated here).
[45] Ex. 205, Staff Cost of Service Report, pp. 48-49; and Ex. 251, Kunst Surrebuttal, Schedule JK-s2.

demolished and removed was $7.44 million.[46]

6. An agreement for sale between LAC and Cortex was reached and Cortex purchased the Forest Park property, including the buildings, other improvements, and land for $8.3 million and an additional $5.7 million for employee and equipment relocation expenses. The sale transaction closed in May of 2014.[47]

7. As part of the sale agreement, LAC retained the right to occupy the premises while it coordinated its move to other facilities.[48] The move from the Forest Park property was coordinated with moves to other facilities and the consolidation of "shared services" employees and functions after the acquisition of MGE.[49]

8. LAC continued to use portions of the Forest Park property for almost a year after the closing.[50] Eventually, LAC relocated management employees to the Shrewsbury and Berkeley service centers and other Forest Park employees were moved to a temporary location in the vicinity. In November 2016, LAC placed its newly constructed facility at 5311 Manchester (Manchester facility) into service where approximately 100 LAC employees responsible for construction and maintenance, leak detection and repair, and other functions were relocated.[51]

9. The Manchester service center location allows LAC to provide quick emergency response time to the city and also allows LAC to continue with its accelerated pipe replacement work that LAC previously performed at its Forest Park

[46] Ex. 251, Kunst Surrebuttal, Schedule JK-s1.
[47] Ex. 205, Staff Cost of Service Report, p. 49; and Ex. 251, Kunst Surrebuttal, p. 2 and Schedule JK-s1, Attachment 6.
[48] Ex. 42, Kopp Rebuttal, p. 8.
[49] Ex. 42, Kopp Rebuttal, p. 8; and Ex. 205, Staff Cost of Service Report, p. 49.
[50] Ex. 251, Kunst Surrebuttal, p. 4; and Ex. 42, Kopp Rebuttal, p. 8.
[51] Ex. 205, Staff Cost of Service Report, p. 49; and Ex. 42, Kopp Rebuttal, p. 9.

facility.[52]

10. The Manchester facility was a "partial replacement" for the Forest Park property and has an approximate $7.7 million rate base value.[53]

11. The Manchester facility was the only capital expenditure in this case used to "replace" the Forest Park functions.[54]

12. The Manchester facility is more cost efficient to operate; however, the capital cost is substantially greater than the existing Forest Park facility.[55]

13. LAC had owned the Forest Park property for many decades and the original buildings were fully depreciated many years ago. However, more recent capital improvements to the property resulted in additional gross plant of approximately $3.3 million, offset by a depreciation reserve of $1.5 million, leaving a net rate base asset for the capital improvements of $1.8 million at the time of the sale.[56]

14. When the buildings were retired for accounting purposes, LAC credited the Forest Park building asset account by $3.3 million and debited the depreciation reserve account by the same amount. Since the depreciation reserve balance associated with the buildings was $1.5 million prior to the retirement, a negative reserve debit of $1.8 million now exists.[57] Thus, ratepayers will continue paying for the old building (*i.e.* LAC will continue to earn a return on the $1.8 million) while also paying for the new Manchester facility.[58]

---

[52] Ex. 251, Surrebuttal Testimony of Jason Kunst, p. 4.
[53] Ex. 205, Staff Report - Cost of Service, p. 49; and Ex. 251, Kunst Surrebuttal, pp. 3-4 and Schedule JK-s2.
[54] Tr. 1620.
[55] Ex. 43, Kopp Surrebuttal, Schedule SMK-S1.
[56] Ex. 64, Affidavit of Glenn Buck Related to Forest Park, pp. 1-2; and Ex. 251, Kunst Surrebuttal, p. 14.
[57] Ex. 64, Affidavit of Glenn Buck Related to Forest Park, pp. 1-2
[58] Ex. 64, Affidavit of Glenn Buck Related to Forest Park, p. 2; Ex. 438, Robinett True-Up Rebuttal, p. 3; and Tr. 1633 and 1643.

15. LAC's gain or profit from the $8.3 million sale price of property previously included in rate base after subtracting the $1.8 million net book value of the buildings and $700,000 for the land was $5.8 million.[59]

16. LAC used $1.5 million from the gain on the sale of the Forest Park property to make civic contributions for downtown St. Louis rehabilitation.[60]

17. LAC used $1.95 million of relocation proceeds for the purchase of furniture and fixtures at its new offices located at 700 and 800 Market Street.[61] LAC recorded these purchases at a "zero" net book value.[62]

18. In Data Request 388, LAC reported its moving and relocation expenses, but the expenses were not tracked by particular move. With the exception of a lease expense for one of the temporary locations at a cost of $200,000, it was not clear which expenses were used for moving Forest Park employees and equipment and which were used for moving employees and equipment from Olive to Market.[63]

19. LAC did not seek Commission authorization prior to the sale of the Forest Park property.

20. The Forest Park property was necessary and useful in the provision of utility service at the time of its sale.

21. Staff argues that the gain from the sale of the Forest Park property should be shared with ratepayers because LAC sold utility property that was needed for the provision of utility service that had to be replaced with a facility at a higher cost.[64]

---

[59] Ex. 205, Staff Cost of Service Report, p. 49; and Ex. 251, Kunst Surrebuttal, p. 2.
[60] Tr. 1619.
[61] Ex. 42, Kopp Rebuttal, pp. 8-9; and Ex. 251, Kunst Surrebuttal, p. 6.
[62] Ex. 251, Kunst Surrebuttal, p. 6.
[63] Tr. 1649-1650.
[64] Ex. 251, Kunst Surrebuttal, p. 3.

22. With regard to the relocation proceeds, Staff proposes that $3.6 million (the $5.7 million relocation proceeds, less documented moving expenses and less the $1.95 million in capital expenditures for furniture and fixtures) be used to offset the cost of the more expensive Manchester facility.[65]

23. It is just and reasonable to offset the cost of the more expensive replacement facility with the relocation proceeds less the known moving expenses for Forest Park and the capital contributions.

Conclusions of Law

A. A company is required to obtain Commission authorization prior to the sale of any part of its system that is necessary or useful in the performance of its duties to the public.[66]

B. Commission rule 4 CSR 240-40.040 requires a gas utility to use the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) for tracking its regulated property. The FERC USOA for gas utilities proscribes specific treatment for the sale of utility assets that constitute an operating unit or system as follows:

> F. When gas plant constituting an operating unit or system is sold, conveyed, or transferred to another by sale, merger, consolidation, or otherwise, the book cost of the property sold or transferred to another shall be credited to the appropriate utility plant accounts, including amounts carried in account 114, Gas Plant Acquisition Adjustments. The amounts (estimated if not known) carried with respect there-to in the accounts for accumulated provision for depreciation, depletion, and amortization and in account 252, Customer Advances for Construction, shall be charged to such accounts and the contra entries made to account 102, Gas Plant Purchased or Sold. Unless otherwise ordered by the Commission, the difference if any, between (a) the net amount of debits and credits and (b) the consideration received for the property (less

[65] Ex. 251, Kunst Surrebuttal, p. 6.
[66] Subsection 393.190.1, RSMo.

> commissions and other expenses of making the sale) shall be included in account 421.1, Gain on Disposition of Property, or account 421.2 Loss on Disposition of Property (see account 102, Gas Plant Purchased or Sold).[67]

Decision

The Commission has not previously had an opportunity to address how Spire Missouri should handle the accounting for the Forest Park property transaction because the issue was not presented to the Commission for authorization of the transactions. The Commission finds that the ratepayers should not continue to pay for property that was necessary for the provision of utility service and was replaced with a more expensive property.

The sale of the Forest Park property was not purely a land transaction. The appraisal Cortex received was given from the perspective of a client that had no use for the structures and would need the land cleared to build its retail facility. The fact is that these buildings were included in rate base and had an undepreciated net book value of $1.8 million at the time of the sale. This transaction included the sale of the land and the buildings and when the buildings were sold any return on or of the building costs should have been removed from rates.

The FERC USOA for gas utilities proscribes specific treatment for the sale of utility assets that constitute an operating unit or system. Spire Missouri's recording of the transaction reduced the building asset account by $3.3 million. However, its reduction of the depreciation reserve by the same amount ($3.3 million) does not allow for the recognition of the $1.8 million loss on the retirement of the Forest Park buildings

[67] Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act, 18 C.F.R. § Pt. 201, Gas Plant Instructions, *5.Gas Plant purchased or sold, F.*

and misrepresents the effect of the sale on the depreciation reserve. The Commission orders LAC to account for the sale of the Forest Park buildings transaction in accordance with the FERC USOA by increasing its accumulated depreciation reserve by the $1.8 million loss on the retirement of the Forest Park buildings. Neither a return on the $1.8 million undepreciated value of the Forest Park buildings, nor any return of the $1.8 million shall be included in rates going forward. The remainder of the $5.8 million gain properly belongs to the shareholders.

LAC partially replaced the Forest Park buildings with the Manchester facility. LAC also received $5.7 million in moving expenses as part of the sale. It was necessary for LAC to continue to utilize the Forest Park facilities after the completion of the sale and it was necessary to replace a portion of the previous Forest Park facilities with the Manchester facility at greater cost. Although the Manchester facility may be less expensive to operate, it is a much more expensive capital asset than the Forest Park property and rates will include this more expensive capital. Therefore, it is appropriate for the Commission to order a portion of the $5.7 million relocation costs be used to offset the higher costs of the partial replacement facility.

The actual expenses incurred to relocate Forest Park employees could not be determined from the evidence presented, but the $200,000 lease expense and the $1.95 million capital contributions should be deducted from the $5.7 million total before the remainder is used to offset the construction cost of the new Manchester facility. The Commission adopts the Staff’s proposal that Spire Missouri shall create a regulatory liability to record the rate base offset of the relocation expense which shall be amortized over five years beginning with the date the rates set in this case become effective.

II. Kansas Property Tax

A. What is the appropriate amount of Kansas property tax expense to include in MGE's base rates?

B. Should the tracker for Kansas property tax expense be continued?

During the course of the hearing, Spire, Staff, and Public Counsel indicated they reached an agreement regarding Staff's surrebuttal position on the issue of Kansas property tax and the continuation of a tracker for that expense.[68] They further indicated MIEC would waive cross-examination on these issues, but would brief the remaining issues.[69] MIEC did not, however, include any arguments on these topics in its briefs.[70] Thus, it appears that the parties reached agreement on these issues as set out below.

<u>Findings of Fact</u>

1. MGE has natural gas inventory for use in its Missouri gas service area that is stored in the state of Kansas. MGE currently pays Kansas property tax for the natural gas inventory based on its volume of gas costs and the market price of gas as of January 1 of that year.[71]

2. The amount of actual Kansas property taxes paid by MGE since 2009 has been somewhat volatile with a downward trend from 2013 through 2016.[72]

3. Based on actual tax bills received for four of ten counties, the 2017 Kansas property tax amount will increase.[73] Thus, based on those actual tax bills, Staff

[68] Tr. 1628.
[69] Tr. 1628.
[70] *Initial Brief of Missouri Industrial Energy Consumers* (filed January 9, 2018); and *Reply Brief of Missouri Industrial Energy Consumers* (filed January 17, 2018).
[71] Ex. 205, Staff Cost of Service Report, p. 130.
[72] Ex. 252, K. Lyons Surrebuttal, p. 3.
[73] Ex. 252, K. Lyons Surrebuttal, p. 4.

calculated and recommended at the time of its surrebuttal testimony a normalized annual level of Kansas property taxes of $1,454,069 (the average of the taxes for 2009 through 2016).[74] Staff indicated the revised normalized amount would be reflected in its true-up accounting schedules.[75]

4. Because of the volatility of the property tax amount and the Kansas laws pertaining to this property tax,[76] the Commission has previously approved, as part of a stipulation and agreement, a tracker for the Kansas property tax amount.[77] In its Surrebuttal testimony, Staff recommended the tracker continue and be reviewed again in MGE's next general rate case.[78]

Conclusions of Law

The Commission makes no additional conclusions of law for this issue.

Decision

Based on actual tax bills for the 2017 tax year when compared to the actual amounts from 2009-2016, the Commission finds the Kansas property taxes remain volatile, with an increase in 2017 over the previous four years. The Commission further finds that an average of the actual Kansas property tax expense from 2009-2016 ($1,454,069) is an appropriate amount to include in rates as a normalized annual level. Further, because of the past volatility of the Kansas property tax amount, the potential for future volatility given that the tax is set based on one-day price information, and the agreement of Spire, Staff, and Public Counsel, the Commission finds that the Kansas property tax tracker shall be continued.

[74] Ex. 252, K. Lyons Surrebuttal, p. 4.
[75] Ex. 252, K. Lyons Surrebuttal, p. 4.
[76] Ex. 205, Staff Cost of Service Report, pp. 130-136.
[77] Ex. 205, Staff Cost of Service Report, pp. 130-131.
[78] Ex. 252, K. Lyons Surrebuttal, pp. 5-6.

III. Cost of Capital

A. Return on Common Equity – What's the appropriate return on common equity to be used to determine rate of return?

<u>Findings of Fact</u>

1. These issues concern the rate of return Spire Missouri will be authorized to earn on its rate base. Rate base is the net value of the utility's assets. In order to determine a rate of return, the Commission must determine Spire's capital structure and cost of obtaining the capital it needs.

2. To determine a return on equity, the Commission must consider the expectations and requirements of investors when they choose to invest their money in Spire Missouri rather than in some other investment opportunity. As a result, the Commission cannot simply find a rate of return on equity that is unassailably scientifically, mathematically, or legally correct. Such a "correct" rate does not exist. Instead, the Commission must use its judgment to establish a rate of return on equity attractive enough to investors to allow the utility to fairly compete for the investors' dollar in the capital market without permitting an excessive rate of return on equity that would drive up rates for Spire's ratepayers. To obtain guidance about the appropriate rate of return on equity, the Commission considers the testimony of expert witnesses.

3. Three financial analysts testified in the case regarding an appropriate return on equity. David Murray testified on behalf of Staff. Mr. Murray is the Utility Regulatory Manager of the Financial Analysis Unit for the Staff Division of the Missouri Public Service Commission. He holds a Bachelor of Science degree in Business Administration from the University of Missouri – Columbia, and a Master's degree in

Business Administration from Lincoln University. Mr. Murray has been employed by the Commission since 2000 and has offered testimony in many cases before the Commission.[79] Mr. Murray recommends an allowed return on equity of 9.25 percent, within a range of 9.00 percent to 9.50 percent.[80]

4. Michael Gorman testified on behalf of Public Counsel and MIEC. Mr. Gorman is a consultant in the field of public utility regulation and is a Managing Principal of Brubaker & Associates, Inc. He holds a Bachelor of Science degree in Electrical Engineering from Southern Illinois University and a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield.[81] Gorman recommends the Commission allow Spire Missouri a return on equity of 9.20 percent, the midpoint of a recommended range of 8.90 percent to 9.40 percent.[82]

5. Pauline Ahern testified on behalf of Spire Missouri. Ms. Ahern is a consultant in the field of investor-owned utility regulation and is an Executive Director of ScottMadden, Inc. She holds a Bachelor of Arts degree in Economics from Clark University and Master's Degree in Business Administration with a concentration in finance from Rutgers University.[83] Ms. Ahern recommends the Commission allow Spire Missouri a return on equity of 10.35 percent, including a "flotation risk adjustment" of .16 percent and a "business risk adjustment" of .20 percent.[84]

[79] Ex. 206, Staff Report Appendix 1, pp. 42-50.
[80] Ex. 205, Staff Report - Cost of Service, p. 8.
[81] Ex. 407, Gorman Direct, Appendix A, p. 1.
[82] Ex. 407, Gorman Direct, p. 2.
[83] Ex. 38, Ahern Direct, p. 1.
[84] Ex. 38, Ahern Direct, p. 5.

6. A utility's cost of common equity is the return investors require on an investment in that company. Investors expect to achieve their return by receiving dividends and through stock price appreciation.[85] In general, the United States Supreme Court has set out the financial and economic standards to consider in setting the cost of common equity.[86] That is, the Commission must authorize a return on equity sufficient to maintain financial integrity, attract capital under reasonable terms, and be commensurate with returns investors could earn by investing in other enterprises of comparable risk.[87]

7. The financial analysts in this case used a variety of methods to estimate a company's fair rate of return on equity including the Discounted Cash Flow (DCF) method, the Risk Premium Model (RPM), and the Capital Asset Pricing Method (CAPM).[88] The DCF is based on a theory that a stock's current price represents the present value of all expected future cash flows discounted at the investor's required rate of return or cost of capital.[89] The analysts also use variations of the DCF model.[90] The RPM is based on the principle that investors require a higher return to assume a greater risk.[91] Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations.[92] The CAPM assumes the investor's required rate of return on equity is equal to a risk-free rate of interest, plus

[85] Ex. 407, Gorman Direct, p.19.
[86] Ex. 407, Gorman Direct, p. 20.
[87] Ex. 205, Staff Report - Cost of Service, p. 9; and Ex. 407, Gorman Direct, p. 20.
[88] Ex. 38, Ahern Direct, p. 4; Ex. 205, Staff Report - Cost of Service, p. 10; and Ex. 407, Gorman Direct, p. 20.
[89] Ex. 407, Gorman Direct, p. 22.
[90] Ex. 407, Gorman Direct, p. 20.
[91] Ex. 407, Gorman Direct, p. 37.
[92] Ex. 407, Gorman Direct, p. 37.

a risk premium associated with the specific security.[93] Generally, no one method is any more correct than any other method in all circumstances. Analysts balance their use of all three methods to reach a recommended return on equity.

8. Before examining the analysts' use of these various methods to arrive at a recommended return on equity, it is important to look at some other numbers. In 2014, the average authorized return on equity for a gas local distribution company (LDC) was approximately 9.78 percent.[94] Through the first six months of 2017 that dropped to approximately 9.5 percent. However, the most recent data available at the hearing showed that the average for the first three quarters of 2017 was approximately 9.8 percent.[95] Additionally, from 2015 through 2017, there has been a general trend upward in "fully litigated" authorized returns on equity.[96] Further, in the last three quarters of 2017, the United States had its strongest gross domestic product (GDP) growth since 2015.[97]

9. The Commission mentions the average allowed return on equity because Spire Missouri must compete with other utilities all over the country for the same capital. Therefore, the average allowed return on equity provides a reasonableness test for the recommendations offered by the return on equity experts.

10. Mr. Murray testified that he believed the actual cost of common equity for Spire Missouri was in the range of 6.90 percent to 7.70 percent.[98] Mr. Murray also indicated that no state agency had found such a low range to be reasonable for many

[93] Ex. 407, Gorman Direct, pp. 43-44.
[94] Tr. 1366.
[95] Tr. 1366.
[96] Ex. 40, Ahern Surrebuttal, pp. 39-40.
[97] Tr. p. 1299.
[98] Ex. 205, Staff Report - Cost of Service, p. 7 and 39; and Tr. 1290.

years.[99] Thus, instead of recommending that range for an authorized return on equity, he determined that utility capital markets were similar to those in place with the Commission authorized returns of approximately 9.5 percent for Missouri's large electric utilities.[100] Mr. Murray then adjusted that return downward based on his determination of a risk differential between natural gas companies and vertically integrated electric companies.[101] The Commission finds that Mr. Murray's recommended ROE is too low due to its reliance on Commission decisions in cases that had test years in 2014 and 2015, Mr. Murray's ROE recommendation does not consider the improving economy and increasing Federal Reserve interest rates.

11. Gorman's recommended return on equity was calculated very differently than Mr. Murray's but had a similar outcome at 9.2 percent. However, Gorman's return on equity is also too low when compared to average ROEs awarded by other state commissions to similarly situated utilities. Obviously, this Commission is not bound to follow the lead of other commissions in setting an appropriate ROE. Even so, Spire Missouri must compete in the capital market with those other utilities. Further, Gorman's analysis failed to take into account areas where Spire Inc. faces risk above that in faced by his proxy group. When appropriately adjusted for business risk and flotation cost adjustments, and other corrections suggested by Ms. Ahern, Gorman's common equity cost rates would be 9.89 percent, also very close to the national average.[102]

---

[99] Tr. 1292.
[100] *In the Matter of Union Electric Company d/b/a Ameren Missouri,* Case No. ER-2016-0179 *(Order Approving Unanimous Stipulation and Agreement,* issued March 8, 2017) pp. 2-3; *In the Matter of Kansas City Power & Light Company,* Case No. ER-2016-0285 *(Report & Order,* issued May 3, 2017) at p. 22.
[101] Tr. 1299-3001; and Ex. 205, Staff Report - Cost of Service, p. 8.
[102] Ex. 39, Ahern Rebuttal, pp. 47-70.

12. In contrast to Mr. Murray and Gorman, the Commission finds Ms. Ahern's return on equity recommendation is too high. Ms. Ahern's methods are inconsistent in that she ignores the corporate parent structure (Spire Inc.) of Spire Missouri in determining a business risk adjustment for size, yet she compares LAC and MGE as stand-alone companies to other parent company entities in her proxy group.[103] While Spire Missouri operates through its LAC and MGE subsidiaries, Atmos Energy, New Jersey Resources, and Northwest Natural Gas, all publicly traded parent companies in the proxy group, also provide gas service via their subsidiaries.[104] When compared at the parent-company level, Spire Inc. falls in the middle of the other parent companies with regard to size.[105]

13. Considering the range of the expert ROE recommendations from 9.2 percent to 10.35 percent and each of their flaws, the most recent national average of 9.8 percent, and appropriate adjustments for risk, the growing economy, and the anticipated increase in Federal Reserve interest rates, the Commission finds the most reasonable authorized return on equity is 9.8 percent.

Conclusions of Law

A. In assessing the Commission's ability to use different methodologies to determine just and reasonable rates, the Missouri Court of Appeals has said:

> Because ratemaking is not an exact science, the utilization of different formulas is sometimes necessary. … The Supreme Court of Arkansas, in dealing with this issue, stated that there is no 'judicial mandate requiring the Commission to take the same approach to every rate application or even to consecutive applications by the same utility, when the commission in its expertise, determines that its previous methods are unsound or inappropriate to the particular application' (quoting Southwestern Bell

[103] Ex. 38, Ahern Direct, Schedule PMA-D3, p. 3.
[104] Ex. 38, Ahern Direct, Schedule PMA-D3, p. 3, 5, and 6.
[105] Ex. 38, Ahern Direct, Schedule PMA-D3.

> Telephone Company v. Arkansas Public Service Commission, 593 S.W. 2d 434 (Ark 1980).[106]

Furthermore,

> Not only can the Commission select its methodology in determining rates and make pragmatic adjustments called for by particular circumstances, but it also may adopt or reject any or all of any witnesses' testimony.[107]

B. The Court of Appeals has recognized that the establishment of an appropriate rate of return is not a "precise science":

> While rate of return is the result of a straight forward mathematic calculation, the inputs, particularly regarding the cost of common equity, are not a matter of 'precise science,' because inferences must be made about the cost of equity, which involves an estimation of investor expectations. In other words, some amount of speculation is inherent in any ratemaking decision to the extent that it is based on capital structure, because such decisions are forward-looking and rely, in part, on the accuracy of financial and market forecasts.[108]

C. In addition to being imprecise, determining a return on equity also involves balancing a utility's need to compensate investors against its need to keep prices low for consumers.[109]

D. Missouri court decisions recognize that the Commission has flexibility in fixing the rate of return, subject to existing economic conditions.[110] "The cases also recognize that the fixing of rates is a matter largely of prophecy and because of this commissions, in carrying out their functions, necessarily deal in what are called 'zones of reasonableness', the result of which is that they have some latitude in exercising this

---

[106] *State ex rel. Assoc. Natural Gas Co. v. Public Service Commission,* 706 S.W. 2d 870, 880 (Mo. App. W.D. 1985).
[107] *State ex rel. Assoc. Natural Gas Co. v. Public Service Commission,* 706 S.W. 2d 870, 880 (Mo. App. W.D. 1985).
[108] *State ex rel. Missouri Gas Energy v. Public Service Commission*, 186 S.W.3d 376, 383 (Mo App. W.D. 2005).
[109] *State ex rel. Pub. Counsel v. Pub. Serv. Comm'n*, 274 S.W.3d 569, 574 (Mo. Ct. App. 2009).
[110] *State ex rel. Laclede Gas Co. v. Public Service Commission*, 535 S.W.2d 561, 570-571 (Mo. App. 1976).

most difficult function."[111] Moreover, the United States Supreme Court has instructed the judiciary not to interfere when the Commission's rate is within the zone of reasonableness.[112]

Decision

In order to set a fair rate of return for Spire, the Commission must determine the weighted cost of each component of the utility's capital structure. One component at issue in this case is the estimated cost of common equity, or the return on equity. Based on the competent and substantial evidence in the record, on its analysis of the expert testimony offered by the parties, and on its balancing of the interests of the company's ratepayers and shareholders, as fully explained in its findings of fact and conclusions of law, the Commission finds that 9.8 percent is a fair and reasonable return on equity for Spire Missouri. That rate is nearly the midpoint of all the experts' recommendations and is consistent with the national average, the growing economy, and the anticipated increasing interest rates. The Commission finds that this rate of return will allow Spire Missouri to compete in the capital market for the funds needed to maintain its financial health.

[111] *State ex rel. Laclede Gas Co. v. Public Service Commission*, 535 S.W.2d 561, 570 -571 (Mo. App. 1976). In fact, for a court to find that the present rate results in confiscation of the company's private property, that court would have to make a finding based on evidence that the present rate is outside of the zone of reasonableness, and that its effects would be such that the company would suffer financial disarray. *Id*.

[112] *State ex rel. Public Counsel v. Public Service Commission*, 274 S.W.3d 569, 574 (Mo. App. 2009). *See, In re Permian Basin Area Rate Cases,* 390 U.S. 747, 767, 88 S.Ct. 1344, 20 L.Ed.2d 312 (1968) ("courts are without authority to set aside any rate selected by the Commission [that] is within a 'zone of reasonableness' ").

B. Capital Structure – What capital structure should be used to determine the rate of return?

C. Cost of Debt – What cost of long-term debt should be used to determine the rate of return?

D. Should short-term debt be included in the capital structure? If so, at what cost?

Findings of Fact

1. Another essential ingredient of the cost-of-service ratemaking formula is the rate of return, which is premised on the goal of allowing a utility the opportunity to recover the costs required to secure debt and equity financing. To arrive at a rate of return, in addition to considering the return on equity, the Commission must examine an appropriate ratemaking capital structure and Spire Missouri's embedded cost of debt.

2. Spire Inc. has been acquiring gas distribution utilities since 2013. Spire Inc. through Spire Missouri (known as Laclede Gas Company at the time) acquired the assets of MGE in 2013. That transaction was structured as a direct asset purchase with no long-term debt assumed in the transaction. Spire Inc. (known as The Laclede Group at the time) issued new equity and Spire Missouri issued debt to fund the purchase of MGE's assets.[113]

3. Spire Inc.'s other utility acquisitions were structured as stock purchases of a subsidiary corporation owning the utility systems. Spire Inc. funded its acquisition of Alagasco by issuing debt, issuing equity, and assuming $250 million of Alagasco debt. Spire Inc. acquired EnergySouth similarly with the assumption of $67 million of Mobile Gas debt. The acquisitions of Alagasco and EnergySouth resulted in Spire Inc. having a more leveraged capital structure than its subsidiary, Spire Missouri.[114]

[113] Ex. 205, Staff Report - Cost of Service, p. 18.
[114] Ex. 205, Staff Report - Cost of Service, p. 18.

4. Spire Inc. holds natural gas utilities which are regulated in three states and a pipeline company subject to the jurisdiction of FERC.

5. Spire Missouri's expert witnesses with regard to capital structure, Pauline Ahern, Glenn Buck, Robert Hevert, and Steven Rasche, recommended the Commission adopt the capital structure of the utility, Spire Missouri, and not that of the parent company, Spire Inc.[115]

6. Spire Missouri's actual capital structure on the true-up date, September 30, 2017, was 54.2 percent common equity and 45.8 percent long-term debt.[116]

7. Spire Missouri has an independently determined capital structure in that its debt is secured by its own assets and not the assets of Spire Inc. or any of Spire Inc.'s other subsidiaries.[117] Additionally, Spire Missouri's assets do not guarantee the long-term debt of its parent or of any of Spire Inc.'s other public utilities or of Spire Marketing or Spire STL Pipeline.[118] Further, the Commission must approve any long-term debt issuances made by Spire Missouri.[119]

8. Spire Missouri's stand-alone capital structure supports its own bond rating.[120]

9. Spire Missouri's capital structure ratios are consistent with the capital structure ratios used by Staff in the most recent Laclede Gas Company rate case

[115] Ex. 21, Buck Surrebuttal, p. 2; Ex. 22, Buck True-Up Direct, p. 2; Ex. 36, Hevert Surrebuttal, pp 15-16; Ex. 37, Rasche Surrebuttal, p. 18; and Ex. 40, Ahern Surrebuttal, pp. 24-25.
[116] Ex. 21, Buck Surrebuttal, p. 2; Ex. 22, Buck True-Up Direct, p. 2; and Ex. 36, Hevert Surrebuttal, p. 3.
[117] Ex. 39, Ahern Direct, pp. 3-4; and Tr. 1307.
[118] Ex. 39, Ahern Direct, p. 4; and Tr. 1307-1308.
[119] Ex. 39, Ahern Direct, pp. 3-4.
[120] Ex. 39, Ahern Direct, p. 4.

involving the MGE division, File No. GR-2014-0007. In that proceeding, Staff used the capital structure of 53.56 percent common equity and 46.44 percent long-term debt.[121]

10. Spire Missouri's capital structure ratios as of the true-up date are based on the actual capital structure that finances the assets and operations of the public utility for which the Commission is setting rates in this proceeding.[122]

11. Spire Inc.'s capital structure contains capital that has not been directly used to fund investments in LAC and MGE (such as the debt issued to acquire Alagasco and EnergySouth and the debt assumed from those companies).[123] Additionally, the capital structure of the parent, Spire Inc. includes the common equity of other public utilities and unregulated operations.[124] However, Spire Missouri does not have access to capital that is being used by Spire Inc.'s other subsidiaries.[125]

12. Spire Inc.'s actual capital structure on September 30, 2017, was 48.71 percent common equity and 51.20 percent long-term debt.[126]

13. Michael Gorman, on behalf of Public Counsel and MIEC, recommended a capital structure of Spire Missouri consisting of 47.2 percent equity and 52.8 percent long-term debt.[127] Mr. Gorman's recommendation reflects the removal of $210 million of common equity for goodwill.[128] Mr. Gorman argues that the utility capital structure should be used, but that a $210 million deduction from common equity should be made "to remove the capital supporting the goodwill asset."[129] With that adjustment (and

[121] Ex. 60, Staff Accounting Schedule in GR-2014-0007; and Tr. 1304.
[122] Ex. 37, Rasche Surrebuttal, p. 18; and Tr. 1311.
[123] Ex. 205, Staff Report - Cost of Service, pp. 24-25.
[124] Tr. 1311-1312.
[125] Ex. 39, Ahern Rebuttal, p. 7.
[126] This was determined using the ratios provided by Staff, but removing the short-term debt.
[127] Ex. 414, Gorman Rebuttal, p. 5.
[128] Ex. 414, Gorman Rebuttal, pp. 4-5.
[129] Ex. 414, Gorman Rebuttal, p. 14.

another that was resolved during true-up), Mr. Gorman proposes a capital structure including 47.20 percent common equity, and 52.80 percent long-term debt.[130]

14. According to SNL and Value Line (industry and financial reports), the common equity ratio for the utility peers used by Mr. Gorman was 49.0 and 55.3 percent, respectively, *including* Spire Inc., the parent company in the proxy group.[131] Without including Spire Inc. the average common equity ratio was 50.42 and 56.5, respectively.[132]

15. Mr. Gorman admitted that his capital structure proposal was "a little light on common equity. . . ."[133]

16. The Stipulation and Agreement in File No. GM-2013-0254 indicates that the parties intended to prevent Spire Missouri from recovering the acquisition premium (the goodwill balance) from the purchase of MGE in rates.

17. The MGE acquisition by Laclede Gas Company was financed with both debt and equity. The acquisition financing, which included both debt and equity, funded the MGE transaction in its entirety, including both tangible utility assets and goodwill.[134]

18. Mr. Rasche testified that, with the exception of project financing, capital is not raised to support a specific asset.[135]

19. Cash is fungible. A particular dollar cannot be traced from the initial dollar invested to the specific asset purchased. Specific portions of the financing were not raised to fund specific portions of the acquisition.[136]

[130] Ex. 414, Gorman Rebuttal, p. 14.
[131] Ex. 407, Gorman Direct, Schedule MPG-3.
[132] Ex. 407, Gorman Direct, Schedule MPG-3.
[133] Tr. 1376. See also, Tr. 1375 (Mr. Gorman testified, "I found that my adjustment to the Company's capital structure has a relatively thin amount of common equity.")
[134] Ex. 36, Hevert Surrebuttal, p. 7; and Ex. 37, Rasche Surrebuttal, p. 4.
[135] Ex. 37, Rasche Surrebuttal, p. 4.

20. No portion of the $210 million goodwill asset is included in the company's rate base.[137]

21. Mr. Gorman's proposed adjustment is inconsistent with the actual method by which the MGE acquisition was financed, it ignores the basic financial principle of capital fungibility, and it is inconsistent with how other assets are treated.[138]

22. David Murray, on behalf of Staff, recommended a capital structure based on Spire Inc.'s consolidated capital structure with the inclusion of short-term debt.[139] He used Spire Inc.'s actual capital structure as of September 30, 2017, and included an average amount of short-term debt in excess of an average amount of construction-work-in-progress (CWIP) for the period September 30, 2014, through September 30, 2017. This capital structure consists of 45.56 percent common equity, 47.97 percent long-term debt and 6.47 percent short-term debt.[140]

23. Mr. Murray used five natural gas companies (Atmos Energy, Northwest Natural Gas, Southwest Gas, OneGas, and Spire Inc.) as his proxy group for his cost of capital analysis.[141] The five-year average common equity ratios for the natural gas companies in Staff's proxy group were: Atmos Energy, 53.73 percent; North West Natural Gas, 53.34 percent; Southwest Gas, 48.85 percent; and Spire Inc., 53.53 percent.[142]

---

[136] Ex. 36, Hevert Surrebuttal, p. 11.
[137] Ex. 36, Hevert Surrebuttal, p. 13, citing Noack True-Up Direct, Laclede Gas Company, Schedule B (PDF 12) and Missouri Gas Energy Schedule B (PDF 55).
[138] Ex. 36, Hevert Surrebuttal, p. 14.
[139] Ex. 205 Staff Report, p.7; and Ex. 265, Murray Surrebuttal, p.2, 4, and Schedule 1-1.
[140] Ex. 205, Staff Report - Cost of Service, p. 7; and Ex. 265, Murray Surrebuttal, p.2, 4, and Schedule 1-1.
[141] Ex. 205, Staff Report - Cost of Service, Appendix 2, Schedule 8.
[142] Ex. 38, Ahern Direct, Schedule PMA-D2, page 2 of 2. (The five-year common equity ratio for OneGas was not in the record.)

24. None of Staff's proxy companies had five-year average common equity ratios as low as Staff's proposed 45.56 percent common equity ratio (or Mr. Gorman's proposed 47.20 percent) for Spire Missouri.

25. Similarly, Ms. Ahern's seven proxy natural gas companies had common equity ratios with the five-year average common equity ratio ranging from 53.46 percent in 2014 to 57.52 percent during the period of 2011-2015.[143]

26. In the last Laclede Gas Company rate case involving the MGE division, File No. GR-2014-0007, the Staff utilized a common equity ratio of 53.56 percent and a long-term debt ratio of 46.44 percent. This ratio is substantially similar to the 54.20 percent common equity ratio and 48.50 percent long-term debt ratio proposed by Spire Missouri in this proceeding.[144]

27. Staff also argues that short-term debt should be included if gas inventories for LAC are included in rate base.[145] While the specific issue of gas inventory carrying costs is addressed elsewhere in this Report and Order, Staff's approach is inconsistent with the fact that every other gas distribution company in Missouri, as well as Spire Missouri's MGE division, currently have these gas inventories in rate base. [146] Further, only rarely has short-term debt been included in the capital structure of major public utilities.[147]

28. Additionally, LAC's gas inventory is approximately $82 million, while Staff proposes to include $283 million of short-term debt in the capital structure, using the

[143] Ex. 38, Ahern Direct, Schedule PMA-D2.
[144] Tr. 1305-1306.
[145] Ex. 259, Sommerer Surrebuttal, pp. 3-5.
[146] Ex. 259, Sommerer Surrebuttal, pp. 3-5.
[147] Tr. 1510-1511.

parent's capital structure.[148] Thus, the amount of short-term debt Staff proposes to include in the capital structure is far in excess of the value of LAC's gas inventories.

29. The average level of construction work in progress and other short-term assets exceeds the amount of short term debt outstanding during the true-up period after taking into consideration a September 15, 2017 funding of $170 million of long-term debt instruments.[149] Mr. Murray's proposal to add short-term debt to the capital structure ignores this fact by using a three-year average rather than the customary "point in time" analysis of short term debt.[150]

30. It is not uncommon to include short-term assets such as cash working capital and materials and supplies in rate base.[151]

31. Spire Missouri's actual embedded cost of long-term debt is 4.123 percent as of the end of the true-up period, September 30, 2017.[152]

Conclusions of Law

A. Rejecting Mr. Gorman's proposed adjustment to reduce common equity by the $210 million goodwill balance is consistent with the Commission-approved Stipulation and Agreement in File No. GM-2013-0254. The Stipulation and Agreement states, at Subparagraph 3.a., "[n]either Laclede Gas [Company] nor its MGE division shall seek either direct or indirect rate recovery or recognition of any acquisition premium in any future general ratemaking proceeding in Missouri." The goodwill balance has been removed from rate base.

[148] Ex. 265, Murray Surrebuttal, Schedule DM-s1-1, p. 1.
[149] Ex. 22, Buck True-Up Direct, p. 2; Ex. 37, Rasche Surrebuttal, p. 3; and Tr. 1269-70.
[150] Ex. 37, Rasche Surrebuttal, p. 4.
[151] Tr. 1502.
[152] Ex. 68, Noack True-up Direct, Schedule F.

Decision

The Commission finds that the capital structure of Spire Missouri without short-term debt is the reasonable capital structure for ratemaking purposes in this case. Similarly, the Commission determines that the cost of debt should be the cost of Spire Missouri's cost of long-term debt.

The Commission's decision on capital structure is supported by the facts set out above including that Spire Missouri has an independently determined capital structure with its own long-term debt issuances secured by its own assets that are the subject of this rate case. These assets do not secure the debt of the parent or its other utilities or unregulated operations. In addition, while the Commission previously used the consolidated capital structure of the parent, Laclede Gas Company, it made up almost the entire holding company. Thus, a consolidated capital structure was basically the utility specific capital structure. Currently, however, the parent, Spire Inc., holds five utilities in three different states and is applying to build an interstate pipeline that will be subject to the FERC oversight. Thus, if the parent company's capital structure were used, regulatory policies employed by commissions in other two other states and at FERC, and financing practices followed by utilities or entities not regulated by the Commission, would affect the rates customers pay in Missouri. The changes to the company and the other facts set out above make it reasonable to use the utility-specific capital structure in this case, and not the consolidated capital structure.

Mr. Gorman's proposed adjustment is rejected. The Commission was not persuaded by Mr. Gorman's testimony regarding a reduction for goodwill. No portion of the $210 million goodwill asset is included in the company's rate base. Because cash is fungible, goodwill cannot be singled out to be considered financed only through equity. The evidence presented by Spire Missouri's four expert witnesses was more persuasive than Mr. Gorman's testimony on these issues. As shown by the facts set out above, Mr. Gorman's proposal is inconsistent with the actual method by which the MGE acquisition was financed, it ignores the basic financial principle of capital fungibility, and it is inconsistent with how other assets are treated. Further, if adopted, Mr. Gorman's proposal would reduce Spire Missouri's cash flows, increasing the risk of impairment of the goodwill asset. Because the GM-2013-0254 Stipulation and Agreement calls for customers to be held harmless from the costs of impairment of the goodwill asset, Mr. Gorman's proposal actually presents the risk of a cycle in which investors are subject to increasing risks and decreasing returns, eventually threatening Spire Missouri's ability to efficiently raise capital.

The Commission also finds Spire Missouri's witnesses to be more persuasive than Staff's witness with regard to capital structure and the inclusion of short-term debt. Staff's recommended capital structure is not consistent with: the capital structures of Staff's own proxy natural gas companies; the Commission's long-held precedent to exclude short-term debt from major public utility's capital structures; or the Staff's previously used capital structure in the true-up proceeding of Laclede's last rate case. For these reasons, the Staff's proposed capital structure is rejected.

Further, the Commission finds that short-term debt should not be included in the capital structure, even though the Commission is also finding in this Report and Order that the gas inventory carrying charges should now be recovered through rate base (see the gas inventories section below). The amount of short-term debt Staff proposes to include in the capital structure is far in excess of the value of LAC's gas inventories.

The average level of construction work in progress and other short-term assets exceeds the amount of short term debt outstanding during the true-up period after taking into consideration funding of $170 million of long-term debt instruments during the true-up period. Mr. Murray's proposal to add short-term debt to the capital structure ignores this fact by using a three-year average rather than the customary "point in time" analysis of short term debt.

Thus, the Commission determines the appropriate capital structure as of the true-up date is 54.2 percent common equity and 45.8 percent long-term debt. To be consistent with its findings related to capital structure, the Commission further finds that the cost of long-term debt should be based on Spire Inc.'s consolidated embedded cost of long-term debt of 4.123 percent as of September 30, 2017.

IV. Rate Case Expense

A. What is the appropriate amount of rate case expense to include?

B. What is the appropriate normalization period for recovering rate case expense?

<u>Findings of Fact</u>

1. Rate case expense is the sum of the costs a utility incurs in preparing, filing and litigating a rate case. [153]

2. Rate case expenses do not include the payroll or benefits of LAC or MGE employees that charge time to rate case expense. Those expenses are included in

[153] Ex. 205, Staff Report - Cost of Service, p. 109.

payroll and benefit expense, and are not allocated between shareholders and ratepayers.[154]

3. Prudence is not the only consideration in determining what costs should be included in rates; the benefit to customers must also be considered when deciding what costs are reasonable for customer rates. Rate case expense can benefit both utility shareholders and customers, though often in different ways. A utility and its shareholders directly benefit from this expense because generally these costs are incurred in order to ensure an opportunity to receive a reasonable return on their investment. Customers benefit generally from being served by financially healthy utilities with the ability to provide safe and adequate service at just and reasonable rates.[155]

4. The consumer groups participating in this rate case were represented by hired counsel, and some also hired expert witnesses. While Spire Missouri is able to recoup the costs of its legal counsel and expenses through utility service rates, Public Counsel, the entity representing ratepayers, operates within a tight annual budget, and the intervenors pay their own legal and expert witness expenses.[156]

5. Spire Missouri's witness testified that the company enters into a rate case with an estimate of its rate case expenses but had no firm ceiling or other mechanism in place to limit those expenses.[157]

6. When LAC and MGE filed their direct case, Spire Missouri had budgeted $994,447 ($397,779 for MGE and $596,668 for LAC) of Missouri jurisdictional rate case

[154] Ex. 255, Majors Surrebuttal, p. 6.
[155] Ex. 205, Staff Report - Cost of Service, p. 111 and 114.
[156] Ex. 205, Staff Report - Cost of Service, pp. 109-112.
[157] Tr. 1713-1715.

expenses with the annual expense being $132,593 for MGE and $198,889 for LAC.[158]

7. At hearing, Spire Missouri's estimated rate case expense had risen to $1.3 million, but it had already exceeded that estimate,[159] "largely because [Spire Missouri] had more issues than [it] expected."[160]

8. LAC and MGE have historically incurred relatively low levels of rate case expense compared to other Missouri utilities. In this case, LAC and MGE have incurred rate case expenses substantially higher than those historical levels. In three prior LAC rate cases and four prior MGE rate cases, total rate case expense exceeded $1 million on only one occasion.[161]

9. Approximately half of the issues in this case were raised by Spire Missouri, which has a high level of discretion and control over the content and methodologies proposed in the rate case.[162]

10. Awarding a utility all of its incurred rate case expenses could provide that utility with a significant financial advantage over other participants in the rate case process, who may be constrained by budgetary and other financial restrictions. Such a practice does not encourage reasonable levels of cost containment in the utility's rate case expense decisions.[163]

11. One incentive for a utility to limit its rate case expense is for the shareholders to share that rate case expense.[164]

---

[158] Ex. 28, Noack Direct, p. 21, Schedule MRN_D1, Schedule H-10, and Schedule MRN_D2, Schedule H-10.
[159] As of September 30, 2017, Spire Missouri's total amount of incurred rate case expenses were $1,393,399. (Ex. 254, Majors Surrebuttal, p. 3).
[160] Tr. 1714.
[161] Ex. 255, Majors Surrebuttal, pp. 5-6.
[162] Tr. 1666 and 1707-1708; and Ex. 205, Staff Report - Cost of Service, pp. 111-112.
[163] Ex. 205, Staff Report - Cost of Service, p. 111.
[164] Ex. 205, Staff Report - Cost of Service, p. 113; and Tr. 1701 and 1777-1778.

12. Spire Missouri requested a three-year amortization of all prudently incurred rate case expenses with a three-year amortization of all those expenses except the current depreciation study. For the depreciation study, Spire Missouri requested a five-year amortization.[165]

13. Staff recommended that the proposed rate case expenses be recovered via a sharing mechanism between the ratepayers and the shareholders based on the ratio of LAC and MGE's Commission-authorized revenue requirement increase to their requested revenue requirement increase, net of Staff's adjustments. Staff's recommended methodology is similar to a sharing mechanism in the *Report and Order* in Case No. ER-2014-0370, Kansas City Power & Light Company's most recent rate case.[166]

14. Staff recommended the ultimately allowed rate case expense be split among LAC and MGE 53.5 percent and 46.5 percent, respectively, based on each division's requested revenue requirement increase. Staff further recommended that rate case expense be normalized over four years, the approximate time between rate cases for both LAC and MGE.[167]

15. Staff proposed one disallowance for the procurement of an outside consultant firm, ScottMadden, to perform a Cash Working Capital study. Staff proposed that this expense be born entirely by the shareholders and not be shared with the ratepayers because it was not a prudent expense.[168]

16. Public Counsel also recommended a disallowance for the expenses

[165] Ex. 28, Direct Testimony of Michael R. Noack, p. 21
[166] *In the Matter of Kansas City Power & Light Company,* issued September 2, 2015.
[167] Ex. 254, Majors Surrebuttal, p. 3.
[168] Ex. 205, Staff Report - Cost of Service, p. 114-115; Ex. 255, Majors Surrebuttal, p. 8; and Tr. 1745.

related to Spire Missouri's witness, Thomas J. Flaherty, because of the high hourly rate charged by this expert.[169]

17. The company also admitted that it purposefully takes the more "aggressive" positions and builds "a little bit of cushion" into its requests.[170]

18. Part of the rate case expense was the cost of Commission-ordered customer notices.[171] The cost of providing those notices was $436,000.[172]

19. Gas utilities are required to file a depreciation study every five years.[173] This rate case coincided with the required filing of a depreciation study. The cost of the depreciation study was $54,114.[174]

20. Spire Missouri has pursued issues and incurred rate case expenses in this case that largely benefit only the shareholders, such as employing an outside expert witness to support its recommended return on equity of 10.35 percent, the highest of any large Missouri utility including two utilities owning nuclear power plants, and litigating the Forest Park property issue.[175]

21. Spire Missouri has pursued more new, unique shareholder-focused ratemaking tools in this case to insulate shareholders from risk, such as three new tracking mechanisms (environmental expense tracker, cyber security tracker, and major capital projects tracker) and a revenue stabilization mechanism.[176]

22. Spire Missouri has pursued utility expenses that are highly discretionary, do not benefit customers, and are typically allocated entirely to shareholders, such as

[169] Tr. 1721 and 1841.
[170] Tr. pp. 1712-1713.
[171] *Order Setting Local Public Hearings and Directing Notice*, (issued June 28, 2017).
[172] Tr. 1701.
[173] 4 CSR 240-3.160(1)(A).
[174] Tr. 1722
[175] Ex. 255, Majors Surrebuttal, p. 7; and Tr. 1710.
[176] Ex. 255, Majors Surrebuttal, p. 7.

incentive compensation tied to earnings per share and a retention mechanism, a onetime adder to ROE for its claimed benefits of acquisitions in Alabama and Mississippi, and performance metrics.[177]

23. Spire Missouri's witness for rate case expense testified that the basic "goal" of the rate case is to receive its revenue requirement increase, that "there is a little bit of cushion built into what [Spire] asked for[,]"[178] and that the company never expected to actually receive that amount.[179] Such a request is purely for the benefit of the shareholders.

24. Public Counsel filed an earnings complaint against LAC and MGE in April 2016.[180] That complaint was stayed in October 2016 pending the filing of these rate cases and then consolidated with these cases in August 2017.[181]

Conclusions of Law

A. Under Missouri law, the Commission must set just and reasonable rates.[182] In a rate case, the Commission has broad discretion to determine which expenses a utility may recover from ratepayers. The Missouri Supreme Court has stated that the Commission's statutory power and authority to set rates "necessarily includes the power and authority to determine what items are properly includable in a utility's operating expenses and to determine and decide what treatment should be accorded

[177] Ex. 255, Majors Surrebuttal, pp. 7-8; and Tr. 1709.
[178] Tr. 1712-1713.
[179] Tr. 1711-1713.
[180] File No. GC-2016-0297.
[181] File No. GC-2016-0219, *Order Granting Motion to Stay Proceedings,* issued October 5, 2016; and *Order Granting Motion to Lift Stay and Consolidate Cases*, issued August 11, 2017.
[182] Section 393.130.1, RSMo, "…All charges made or demanded by any…electrical corporation … shall be just and reasonable and not more than allowed by law or by order or decision of the commission…"

such expense items."[183] The Commission's authority extends to allocating an expense between certain classes or groups of ratepayers[184] and to requiring company shareholders to bear expenses the Commission finds to be unreasonable or unnecessary.[185]

B. Section 393.1012, RSMo, does not require Spire Missouri to file a rate case every three years. Instead, that statute permits the company to continue collecting its authorized infrastructure replacement surcharge (ISRS) so long as it files a rate case every three years. The company could choose to cease collections of the ISRS rather than file a rate case.

C. Commission rule 4 CSR 240-3.160(1)(A) requires a gas utility to conduct a depreciation study every five years.

D. The Commission has previously found rate case expense sharing was just and reasonable. In a 1986 decision, *In the Matter of Arkansas Power and Light Company*, the Commission "adopted Public Counsel's proposed disallowance of one-half of rate case expense."[186] The Commission also acknowledged this authority in a number of other cases.[187]

E. More recently, the Commission determined that rate case expense should be shared between the ratepayers and shareholders.[188] That decision was upheld by the

---

[183] *State ex rel. City of W. Plains v. Pub. Serv. Comm'n*, 310 S.W.2d 925, 928 (Mo. 1958). See also, *State ex rel. KCP & L Greater Missouri Operations Co. v. Missouri Pub. Serv. Comm'n*, 408 S.W.3d 153, 166 (Mo. App. 2013).

[184] *State ex rel. City of W. Plains v. Pub. Serv. Comm'n*, 310 S.W.2d at 934.

[185] *State ex rel. KCP & L Greater Missouri Operations Co. v. Missouri Pub. Serv. Comm'n*, 408 S.W.3d at 164-165.

[186] Report and Order, File No. ER-85-265, 28 Mo. P.S.C. (N.S.) 435, 447 (1986),

[187] See, *In the Matter of Kansas City Power & Light Company,* Report and Order, File Nos. EO-85-185 and EO-85-224, 28 Mo. P.S.C. (N.S.) 229, 263 (1986), and *In the Matter of Missouri Gas Energy,* Report and Order, File No. GR-2009-0355, 19 Mo. P.S.C. 3d 245, 303 (2010).

[188] *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General*

Western District Court of Appeals which found that "the remedy crafted by the [Commission] was a reasonable exercise of the [Commission's] discretion and expertise in determining just and reasonable expenses to be borne by ratepayers."[189]

Decision

The Commission has broad discretion to determine which expenses a utility may recover from ratepayers. The Commission determines that it is reasonable for Spire Missouri shareholders and ratepayers to share most of the rate case expenses in these cases. However, the Commission recognizes that certain expenses, such as the customer notices and the depreciation study, were required by Commission rule or order and should not be part of the shared rate case expense.

In one sense, rate case expense is like other common operational expenses that a utility must incur to provide utility services to customers. Since customers benefit from having just and reasonable rates, it is appropriate for customers to bear some portion of the utility's cost of prosecuting a rate case. However, rate case expense is also different from most other types of utility operational expenses, in that 1) the rate case process is adversarial in nature, with the utility on one side and its customers on the other; 2) rate case expense produces some direct benefits to shareholders that are not shared with customers, such as seeking a higher return on equity; 3) requiring all rate case expense to be paid by ratepayers provides the utility with an inequitable financial advantage over other case participants; and 4) full reimbursement of all rate case expense does nothing to encourage reasonable levels of cost containment.

Rate Increase for Electric Service, Report and Order, File No. ER-2014-0370, issued September 2, 2015.

[189] *In Matter of Kansas City Power & Light Co.'s Request for Auth. to Implement a Gen. Rate Increase for Elec. Serv. v. Missouri Pub. Serv. Comm'n*, 509 S.W.3d 757, 779 (Mo. Ct. App. 2016), reh'g and/or transfer denied (Nov. 1, 2016), transfer denied (Feb. 28, 2017).

Under Missouri law, the Commission must set just and reasonable rates,[190] and rates in this case, that include all of the utility's rate case expense, for the reasons set forth above, are not just or reasonable. However, the Commission determines that it is just and reasonable for ratepayers and shareholders to share rate case expense. In these cases, the just and reasonable sharing mechanism is based on the fact that the issues controlled by the company amounted to about half of the contested issues at hearing. Thus, the shareholders who ultimately controlled 50 percent of the rate case issues should share 50 percent of the rate case expense with the exception of the customer notice cost and the depreciation study were done because of Commission order and rule requirements.

This sharing mechanism is supported by the evidence showing approximately half of the litigated issues in these cases are driven primarily by Spire Missouri, which had complete control over the content and methodologies proposed when it filed its rate cases. Additionally, a number of these litigated issues were unique shareholder-focused ratemaking tools, such as the revenue stabilization mechanism, the requested high rate of return of 10.35 percent, three new tracking mechanisms to limit shareholder risk, and earnings-based incentive compensation which has been consistently denied by the Commission. It was Spire Missouri's decision and entirely within Spire Missouri's power to pursue these issues and to file this rate case and the shareholders stood to benefit from those issues. Also, the company witness admitted that the company "padded" its revenue requirement beyond what it expected to receive by pursuing strong positions on issues it did not expect to win, which is clearly to the benefit of the

[190] Section 393.130.1, RSMo, "…All charges made or demanded by any…electrical corporation … shall be just and reasonable and not more than allowed by law or by order or decision of the commission…"

shareholders over the ratepayers. Finally, rate case expense for this proceeding has far exceeded Laclede and MGE's estimates and their historical rate case expense levels.

Therefore, it is just and reasonable that the shareholders and the ratepayers who both benefited from the rate case, share in the rate case expense. The Commission finds that in order to set just and reasonable rates under the specific facts in this case, the Commission will require Spire Missouri shareholders to cover half of the rate case expense and the ratepayers to cover half with the exception of the cost of customer notices and the depreciation study.

Spire Missouri argues that its shareholders should not have to share rate case expense because it was required to file this rate case by Public Counsel's earnings complaint and by the ISRS statute.[191] The complaint case was stayed while the company made the decision to file a rate case and then ultimately consolidated with these cases. While the company would have been required to participate in that earnings complaint, the decision to instead file a rate case was purely within the discretion of the company.

Further, the ISRS statute does not require that a rate case be filed. Rather, that statute allows the company to continue to collect an authorized ISRS if it files a rate case at least every three years. Thus, Spire Missouri made a decision to continue collecting an ISRS by filing this rate case; it was not required to do so.

Staff and Public Counsel each argue that certain expenses of Spire Missouri in this matter were not prudent and should be born entirely by the shareholders. However, the Commission does not find that any specific individual items of rate case expense were imprudent. A rate case expense sharing mechanism will act as sufficient

[191] Section 392.1012.3, RSMo.

incentive for the company to manage its costs. The Commission also finds that it is appropriate to require a full allocation to ratepayers of the expenses for Spire Missouri's depreciation study, recovered over five years, because this study is required under Commission rules to be conducted every five years. The Commission further finds that it is just and reasonable to require a full allocation to ratepayers of the expenses associated with the Commission-ordered notices provided in this case to be normalized over a four-year period.

The Commission concludes that Spire Missouri should receive rate recovery of 50 percent of its rate case expenses except the cost of the customer notices ($436,000) and the depreciation study ($54,114), which will be wholly included in rates. This amount should be normalized over four years which is roughly equal to the amount of time between rate cases for these companies.

V. PGA/ACA Tariff Revisions --

A. Should LAC have new PGA/ACA tariff provisions pertaining to costs associated with affiliated pipeline transportation agreements?

Findings of Fact

1. The Environmental Defense Fund, through its witness, Gregory M. Lander,[192] proposes a revision to LAC's Purchased Gas Adjustment/Actual Cost Adjustment (PGA/ACA) tariff. The proposed tariff provision would establish explicit standards to guide the Commission's review of the reasonableness of utility costs incurred for transportation of natural gas through an affiliated interstate natural gas

[192] Lander is president of Skipping Stone, LLC, a consulting firm specializing in pipeline transportation issues. Ex. 650, Lander Direct, p. 1.

pipeline.[193]

2. In essence, the proposal would group the company's pipeline capacity into two "buckets" -- a supply reliability capacity bucket and a supply diversity capacity bucket.[194] Those categories would then be separately analyzed to assess whether that capacity is unnecessary or excessive. The Environmental Defense Fund does not propose to undertake such an analysis in this proceeding, but proposes to amend LAC's PGA/ACA tariff to establish procedures to be used in future PGA/ACA cases.[195]

3. The effect of the proposal would be to emphasize the importance of the supply reliability bucket over the supply diversity bucket.[196]

4. Although the review process that would be established by the proposed tariff language would not be limited to any particular gas supply contract, it is apparent that the Environmental Defense Fund is concerned about a 20-year precedent agreement that Spire Missouri has entered into with Spire STL Pipeline, LLC, a proposed interstate pipeline owned by Spire Missouri's corporate parent.[197] The Environmental Defense Fund has challenged that proposed pipeline at the Federal Energy Regulatory Commission (FERC).[198]

5. Staff, which would be required to implement the Environmental Defense Fund's proposed review process, is concerned that the proposal is complicated, does not take into consideration important issues, and may be lacking in sufficient detail to implement.[199]

---

[193] Ex. 650, Lander Direct, p .5.
[194] Ex. 650, Lander Direct, p. 5.
[195] Ex. 650, Lander Direct, pp. 7-8.
[196] Ex. 650, Lander Direct, p. 8.
[197] Ex. 650, Lander Direct, p. 12.
[198] Tr. 1991.
[199] Ex. 233, Crowe Rebuttal, pp. 8-9.

6. If Spire STL Pipeline's pipeline is approved by the FERC, and if Spire Missouri enters into a transportation agreement with that affiliated pipeline, the Commission would review the prudence of that decision in a future ACA review case.[200]

Conclusions of Law

A. The ACA filing procedure allows the Commission an opportunity to review the reasonableness of a gas utility's charges by evaluating its gas acquisition practices during the relevant time period.[201]

B. There is no provision in Missouri law that would require, or authorize, the Commission to preapprove Spire Missouri's management decision to enter into a transportation agreement with a natural gas pipeline.

Decision

The Environmental Defense Fund's proposed revision of LAC's PGA/ACA tariff is unnecessary, premature, and inappropriate. If Spire Missouri ultimately makes a business decision to enter into a transportation agreement with a new interstate natural gas pipeline, the Commission will have an opportunity to review the prudence of that decision in a future ACA case. There is no need to preapprove, or pre-reject that hypothetical decision at this time. If the Environmental Defense Fund or any other stakeholder wants to further examine the establishment of standards for consideration of the prudence of future transportation agreements with affiliated pipelines, they may address such matters as part of the working group the Commission will establish to consider issues regarding Spire Missouri's Cost Allocation Manual.

[200] Tr. 1889.
[201] *See, State ex rel. Associated Natural Gas v. Mo. Pub. Serv. Com'n*, 954 S.W.2d 520 (Mo. App. W.D. 1997).

VI. Cost Allocation Manual

A. Should a working group be created following this rate case to explore ideas for modifying the LAC and MGE CAM?

Findings of Fact

1. Spire Missouri uses a Commission-approved Cost Allocation Manual (CAM) to guide its decisions when assigning costs to its various utility operating companies and affiliates.[202]

2. Spire Missouri's existing CAM was approved by the Commission in 2013.[203] Since that approval, Spire Inc. has acquired Alagasco and Mobile Gas in Alabama and Willmut Gas in Mississippi and has created a new shared services entity.[204] Because of the changes in Spire Inc.'s structure, the existing CAM should be updated.

3. Spire Missouri agrees the existing CAM should be reviewed,[205] and supports the creation of a working group to consider changes to the CAM.[206]

4. Staff is also open to the creation of a working group to revise the CAM.[207]

5. Public Counsel is willing to take part in a working group to revise Spire Missouri's CAM.[208] Public Counsel also advocates for an independent third-party audit of Spire Missouri's affiliate transactions,[209] and argues the audit should take place before the working group starts its review. Public Counsel also suggests the Commission order Spire Missouri to file its new CAM with the Commission for approval

---

[202] Ex. 23, Krick Direct, p. 8.
[203] Ex. 403, Hyneman Direct, p.17. A copy of the CAM can be found at Ex. 403, Hyneman Direct, Schedule CRH-D-3.
[204] Ex. 46, Flaherty Direct, p. 13. *See also*, Ex. 403, Hyneman Direct, p. 17.
[205] Tr. 1850.
[206] Tr. 1859.
[207] Tr. 1890.
[208] Tr. 1913.
[209] Tr. 1913-1914.

no later than six months after rates established in the case become effective.[210]

6. In its testimony, Public Counsel indicates the independent audit should be completed before the end of 2019,[211] and that the specific timing of the audit should be determined in conjunction with Spire Missouri to ensure the company has sufficient resources available to respond to discovery requests.[212]

7. The Environmental Defense Fund does not oppose the creation of a working group to revise the CAM, but urges the Commission to immediately order a particular change in the CAM to establish a process for Spire Missouri to follow before it enters into a transportation agreement with an affiliated pipeline company.[213]

8. Staff opposes the changes to the CAM proposed by the Environmental Defense Fund because they are complicated and lack sufficient detail to be implemented.[214]

Conclusions of Law

A. The Commission's affiliate transaction regulations require Spire Missouri to utilize a CAM with regard to its transactions with affiliated companies.[215]

Decision

The Commission finds that Spire Missouri's CAM should be rewritten, and the best way to accomplish that rewrite is to authorize a working group, comprised of Spire Missouri, Staff, Public Counsel, and any other interested stakeholders, to draft a

[210] *Initial Brief of the Office of the Public Counsel* (filed January 9, 2018), pp. 14-18.
[211] Ex. 401, Azad Direct, p. 5.
[212] Ex. 401, Azad Direct, p. 6.
[213] Tr. 2004. The details of the modification proposed by the Environmental Defense Fund are set forth in Ex. 650, Lander Direct, Schedule EDF-06.
[214] Ex. 233, Crowe Rebuttal, p. 8.
[215] 4 CSR 240-40-015.2(E) and .3(D).

proposed CAM for the Commission's approval. That working group will be established by the Commission in a separate order. The Commission will not delay the working group by ordering the independent audit proposed by Public Counsel. The need for an independent audit will be addressed later in this order.

The Commission will not order Spire Missouri to adopt the specific changes to its CAM proposed by the Environmental Defense Fund. The Commission finds those specific changes to be complicated and difficult to implement. Further, the technical details of the revised CAM should be addressed by the interested stakeholders through the working group that will be authorized. If the Environmental Defense Fund wants to press for its desired changes through that process, it may do so. For the same reason, the Commission will not order Spire Missouri to comply with the other recommendations offered by Public Counsel, as those recommendations can best be addressed by the working group.

B. Should an independent third-party external audit be conducted of all cost allocations and all affiliate transactions, including those resulting from Spire's acquisitions, to ensure compliance with the Commission's Affiliate Transaction Rule, 4 CSR 240-20.015?

Findings of Fact

1. Public Counsel urges the Commission to order Spire Missouri to engage the services of an independent auditor - approved by Staff and Public Counsel – to undertake a focused affiliate transactions audit in order to provide the Commission with an objective and independent review of Spire Missouri's cost allocation practices.[216]

2. Public Counsel believes such an audit should "look at all the charges and

[216] Ex. 401, Azad Direct, p. 5-6 and 23.

the allocation factors and the specific calculations in a level of detail that would far surpass the timeframe that's even allotted for a rate case proceeding."[217] The auditor would also be expected to examine Spire Missouri's compliance with the Commission's affiliate transaction rule and with its existing CAM.[218]

3. Public Counsel does not indicate how much such an audit would cost. Rather, Public Counsel's witnesses at the hearing suggested that the parties could agree on a budget and then solicit bids from interested auditors. It was also suggested that Spire Missouri's shareholders should be responsible for some, or all, of the cost of the audit.[219]

4. Another witness for Public Counsel explained that in the recent Westar/Great Plains Energy merger case, Great Plains Energy agreed to fund the first $500,000 of the cost of a similar audit, with the balance of the audit costs being shared equally between shareholder and ratepayers.[220] That amount might not be required in this case and Public Counsel's witness suggested the parties get together to agree upon a budget for the audit work.[221]

5. Unlike Great Plains Energy in the merger case, Spire Missouri has not agreed to use shareholder funds to pay for an audit.[222]

6. The great majority of Spire Inc.'s expenses are allocated between regulated entities in multiple states, not with unregulated affiliates.[223]

7. One of the major reasons Public Counsel believes an outside audit is

[217] Tr. 1929.
[218] Tr. 1930.
[219] Tr. 1906.
[220] Tr. 1981.
[221] Tr. 1985.
[222] *Reply Brief of Spire Missouri* (filed January 17, 2018), p. 39.
[223] Tr. 1938.

needed is because of the problems it experienced in obtaining responses to discovery requests made to Spire Missouri in this case.[224]

Conclusions of Law

A. Subsection 393.140(5), RSMo, gives the Commission authority to "[e]xamine all persons and corporations under its supervision and keep informed as to the methods, practices, regulations and property employed by them in the transaction of their business." In addition, subsection (8) of that section of the statute gives the Commission power to "examine the accounts, books, contracts, records, documents and papers of any such corporation or person . . . ."

B. Similarly, subsection 386.710(2), RSMo, gives Public Counsel the power and duty to "represent and protect the interests of the public in any proceeding before or appeal from the public service commission."

C. Both Staff and Public Counsel have authority to audit Spire Missouri without the Commission having required the hiring of an outside auditor.

Decision

It is apparent that both Public Counsel and Spire Missouri are frustrated with the other regarding discovery efforts relating to affiliate transactions and cost allocations. The Commission does not need to assess blame for those problems in this order, and neither party brought their discovery concerns to the Commission's attention by filing either a motion to compel, or a motion to protect against discovery, during the course of this case when those concerns could have been addressed and discovery facilitated.[225]

[224] Tr. 1929.
[225] Public Counsel did join, in essence, a motion to compel brought by Staff. At the discovery conference, however, the issues had been worked out by agreement of the parties. (Tr. 25-30). Further, the Regulatory Law Judge advised the parties that if discovery disputes needed to be addressed before a

Regardless, neither those discovery concerns, nor the other concerns described by Public Counsel, justify the expense necessary to undertake such an audit at this time.

It may be that a special audit would be helpful, and the working group the Commission will be establishing to examine Spire Missouri's CAM will be an appropriate forum for that discussion.

The Commission determines it is not necessary or appropriate to order Spire Missouri to hire an outside auditor to examine the company's affiliate transactions and allocations.

C. How Should the Commission Account for an Alleged Downward Trend in the Cost of Spire Shared Services?[226]

Findings of Fact

1. Spire Inc. has adopted a legal shared services entity – Spire Shared Services - to manage the cost of providing common and centralized services across its operating companies and business units.[227]

2. As part of his assessment of the operations of Spire Shared Services, Spire Missouri's witness, Thomas Flaherty, determined that the cost of operating Spire Shared Services was trending downward for the period 2013 through 2016.[228] Specifically, he found that Spire Shared Services' Operations and Maintenance (O&M)

---

scheduled discovery conference, motions could be filed at any time and would be addressed as needed to make sure that deadlines could be met for filing testimony. (Tr. 30-31).

[226] This issue was not identified as such by the parties in the list of issues filed before the hearing. Nevertheless, evidence about it was taken at the hearing, and it was addressed in the briefs of Spire Missouri and Public Counsel.

[227] Ex. 46, Flaherty Direct, p. 13.

[228] Ex. 46, Flaherty Direct, pp. 63-64.

billings to Spire declined by 3.3 percent annually during that period.[229]

3. Public Counsel proposed that the downward cost trend identified by Flaherty will be continued into 2017, and initially proposed a resulting reduction of O&M expense of $4.9 million for LAC, and $2.2 million for MGE.[230]

4. Mr. Flaherty responded to Public Counsel's proposed adjustment through his rebuttal testimony. First, he points out a calculation error in Public Counsel's proposed adjustment resulting from the improper application of after inflation adjusted dollars to a nominal cost base. Public Counsel's witness, Ara Azad recognized that error in her surrebuttal testimony and reduced the proposed reduction in O&M expense to $2,062,266 to LAC and $922,081 for MGE.[231]

5. Flaherty's rebuttal testimony also challenges the basis for Public Counsel's entire proposed adjustment of O&M expenses. As he explains, the decline in shared services charges that he measured between 2013 and 2016 reflects the realization of significant synergies resulting from the merger of LAC and MGE into Spire Missouri, as well as the acquisition of Alagasco by Spire Inc.[232]

Conclusions of Law

The Commission makes no additional conclusions of law on this issue.

Decision

The Commission agrees with Mr. Flaherty that the initial savings resulting from these transactions cannot be assumed to continue at the same rate in 2017. Public Counsel's proposed adjustment is based merely on speculation and will not be

[229] Ex. 46, Flaherty Direct, p. 72.
[230] Ex. 401, Azad Direct, p. 43.
[231] Ex. 426, Azad Surrebuttal, p. 10.
[232] Ex. 47, Flaherty Rebuttal, p. 41.

adopted.

VII. Gas Inventory Carrying Charges

A. Should LAC's natural gas and propane inventory carrying costs be recovered through rate base inclusion, as currently is the case with MGE, or recovered through the PGA/ACA process?

B. Should Line of Credit (LOC) fees be removed from LAC's PGA consistent with inventory inclusion in rate base?

Findings of Fact

1. Currently, MGE recovers the cost of maintaining its gas storage inventories in its base distribution rates. LAC, on the other hand, recovers these gas inventory costs through its PGA/ACA mechanism.[233]

2. Spire Missouri proposed adjustments to LAC's PGA/ACA balances and cost of service to reflect the addition of the average storage inventory costs in rate base, consistent with the approach taken for MGE.[234]

3. Rate base is the utility's plant-in-service at original cost. Rate base often includes other values, as well, such as capitalized construction expenses, including interest and carrying costs, and other charges that the Commission has allowed the utility to capitalize and include in rate base. Also included in rate base are tools and equipment, materials and supplies, fuel stocks, prepayments of expenses, and cash working capital.

4. In 2005, LAC began recovering gas inventory carrying charges at the short-term debt rate through the PGA/ACA process pursuant to a stipulation and

---

[233] Tr. 1445.
[234] Ex. 6, Lobser Direct, pp. 17-18.

agreement in a rate case proceeding, File No. GR-2005-0284.[235] LAC continued to recover the gas inventories associated with "cushion gas" in rate base.[236]

5. In Missouri, LAC is the only local distribution company collecting gas inventory carrying charges in this manner.[237] By putting gas inventory carrying costs back into rate base, these costs for LAC will be consistent with both its sister division, MGE, and with all other local distribution companies in the state.

6. One other benefit of including gas inventory carrying costs in rate base is it reduces the complexity that results from reviewing the separate gas inventory carrying cost recovery mechanism in the annual ACA review process.[238]

7. Staff argues that the gas inventory carrying cost should be included in rate base but only if a comparable amount of short-term debt is included in the capital structure.[239]

8. Public Counsel opposes including natural gas storage costs in rate base arguing that these costs should remain tied to the PGA mechanism because they are more like gas costs than long-term debt.[240]

9. LAC's revenue requirement would be increased by approximately $8 million if gas inventory carrying charges are included in rate base. However, ratepayers will also have the benefit of reduced PGA rates. The effect on revenue requirement for MGE is approximately $3.5 million; however, this is not an incremental

[235] Ex. 205, Staff Report - Cost of Service, p. 62; Tr. 1437 and 1475.
[236] Ex. 205, Staff Report - Cost of Service, p. 62.
[237] Ex. 205, Staff Report - Cost of Service, p. 63; and Tr. 1428.
[238] Ex. 205, Staff Report - Cost of Service, p. 62.
[239] Ex. 227, Sommerer Rebuttal, p. 5. (The Commission has decided the issue of capital structure elsewhere in this order and determined that the capital structure should be that of the utility and should not include short-term debt.)
[240] Ex. 410, Hyneman Rebuttal, pp. 6-16

cost as MGE was already recovering gas inventory carrying costs in rate base.[241]

10. Other inventories, such as materials and supplies, are included in rate base using a 13-month average. A 13-month average helps create a more stable, long-term value for the asset.[242]

11. LAC's gas inventories have cycles whereby gas is injected and withdrawn at various times. However, some amount of gas to meet the reliability needs of LAC's distribution sales customers is maintained in storage year-round, regardless of the length of the injection and withdrawal cycle.[243]

12. Staff and LAC agree that if gas inventory carrying costs are included in rate base, the approximately $4.1 million of carrying costs and associated line of credit fees currently included in the PGA mechanism for gas inventory carrying cost should be removed from the PGA to be consistent.[244]

Conclusions of Law

The Commission makes no additional conclusions of law on this issue.

Decision

The Commission has considered the effects on the ratepayers of removing these costs from the PGA and putting them back in rate base. The Commission has also considered the benefits of doing so and that PGA costs will be reduced potentially offsetting the rate base increases. In balancing the interests of the ratepayers and of the

[241] Tr. 1438; and Ex. 429, Gas Inventory Carrying Costs.
[242] Ex. 205, Staff Report - Cost of Service, pp. 61-63.
[243] Tr. 1517-1518.
[244] Ex. 209, Staff Report - Class Cost of Service, p. 33; *Staff's Initial Post-Hearing Brief* (filed January 9, 2018), p. 44; and *Initial Post-Hearing Brief of Laclede Gas Company and Missouri Gas Energy* (filed January 9, 2018), p. 64.

company, the Commission determines that it is just and reasonable to move LAC's gas storage costs out of the PGA tariff and back into base rates. By doing so, the Commission brings LAC back in line with MGE and every other natural gas local distribution company in Missouri. Additionally, placing gas inventory carrying charges in rate base has the benefit of reducing the complexity resulting from the review of the separate gas inventory carrying cost mechanism in the PGA tariff and in the annual ACA review. The Commission also determines the approximately $4.1 million of carrying costs and associated line of credit fees currently included in the PGA mechanism should also be removed from the PGA to maintain consistency.

VIII. Credit Card Processing Fees

A. Should an amount be included in LAC's base rates to account for fees incurred when customers pay by credit card, in the same manner fees are currently included in MGE's base rates?

Findings of Fact

1. Under LAC's current rate structure, customers who wish to pay their gas bill using a credit or debit card will be assessed a fee by the issuer of the credit card. MGE's customers who pay their bill using a credit or debit card do not pay such a fee. Instead, the credit card fee is paid by MGE and recovered through the rates charged to all customers. Spire Missouri proposes to change LAC's rate structure to match that of MGE, so that customers who pay their bill using a credit or debit card do not have to pay the credit card fee.[245]

2. Currently, approximately 30 percent of MGE's customers - who do not have to pay a fee - pay their bills using a credit or debit card. Approximately 11 percent

[245] Ex. 29, Noack Rebuttal, p. 4.

of LAC's customers - who do have to pay a fee - pay their bills using a credit or debit card.[246]

3. Public Counsel opposes the shifting of costs from customers who use a credit or debit card to pay their bills to all customers, including those who pay their bills by other methods.[247]

4. If LAC customers no longer have to pay a fee to pay their bills with a credit or debit card it is anticipated that more LAC customers will pay their bills by that method.[248]

5. Spire Missouri will benefit if more customers use credit cards because once the payment is made, the credit card company would assume the risk of non-payment.[249] Further, Spire Missouri would get its money sooner and without the risk of taking a bad check,[250] and it might see a reduction in its level of bad debt.[251]

6. While Spire Missouri has not proposed any cost adjustments in this case to recognize any savings from the change in cost recovery of credit and debit card fees,[252] any such benefits that do materialize would reduce the company's cost of service and ultimately benefit ratepayers in a future rate case.[253]

Conclusions of Law

A. Subsection 393.130.3, RSMo, forbids a gas corporation to give an "*undue or unreasonable* preference or advantage" to any "person, corporation or locality."[254]

[246] Ex. 250, Kunst Surrebuttal, p. 19.
[247] Ex. 417, Conner Surrebuttal, p. 3.
[248] Ex. 29, Noack Rebuttal, p. 5.
[249] Ex. 29, Noack Rebuttal, p. 4.
[250] Ex. 30, Noack Surrebuttal, p. 4.
[251] Tr. 1026-1027.
[252] Tr. 1023.
[253] Tr. 1031.
[254] Emphasis added.

The statute implies that not every preference or advantage is "undue" or "unreasonable."

Decision

Public Counsel's argument is based on the premise that those who cause a cost should pay for that cost. That is an appropriate maxim to consider when designing utility rates, but it is not an absolute limitation on the structure of such rates. No customer has a right to pay only their particular costs for receiving utility service, because the cost to serve each customer is different. If nothing else, each customer lives a greater or lesser distance from the interstate pipeline and requires a greater or lesser length of distribution system to obtain their gas supply. If each customer paid only their own individualized costs, Spire Missouri would have to establish thousands of different rates.

In this case, it is reasonable to allow Spire Missouri to recover fees resulting from the use of credit and debit cards to pay LAC bills from all LAC customers rather than from just those customers who use the credit or debit cards to pay their bills, just as it currently does for MGE customers. That policy does not result in an undue or unreasonable preference among customers because all customers can use the convenience of a credit or debit card if that tool is available to them. Ultimately, this is a policy question for which the Commission finds in favor of allowing the company to recover these costs from all ratepayers rather than imposing these costs on only some customers.

Having found that an amount should be included in LAC's base rates to account for fees incurred when customers pay by credit or debit card, the Commission must address the second portion of this issue.

B. If yes, what is an appropriate amount to include in LAC's base rates for credit card fees?

Findings of Fact

1. Staff proposes that Spire Missouri be allowed to recover an annualized amount for credit and debit card processing fees for LAC based on the number of actual credit card payments that occurred for LAC during the 12 months ending June 30, 2017, multiplied by the known and measurable average per payment transaction fee incurred by MGE for the same period.[255]

2. Spire Missouri counters that if customers are allowed to make credit or debit card payments without having to pay a separate fee, then more customers will take advantage of that payment option. Spire Missouri would include an amount in LAC's base rates that assumes the number of such payments by LAC customers will increase by 30 percent the first year, 50 percent the second year, 75 percent the third year, reaching the level of such payments made by MGE customers in the fourth year. Spire Missouri would then average those costs over four years, and include $1,246,619 in base rates to recover those costs.[256]

3. In 2009, the year before MGE took over payment for credit and debit card transaction fees, only four percent of residential customers paid their bills with credit or debit cards. By 2012, the rate of customers paying their bills with credit or debit cards had increased to 14 percent.[257]

4. No one can say with certainty how LAC customers will respond to the

[255] Ex. 250, Kunst Surrebuttal, p. 19; and Ex. 202, Staff's Accounting Schedule 10, p. 7 of 11, indicates this adjustment amounts to $573,853.
[256] Ex. 30, Noack Surrebuttal, p. 5 and Schedule MRN-S1, as corrected at Tr. 1020.
[257] Ex. 250, Kunst Surrebuttal, p. 20.

removal of a separate charge for the use of credit or debit cards to pay bills. In addition, an increase in the use of credit and debit cards could have as yet unknown effects on other utility costs and revenues.[258] As a result, those costs in future years are not yet known and measurable.[259]

Conclusions of Law

A. Spire Missouri proposes that an adjustment be made to account for anticipated changes in customer usage of credit or debit cards in future years. The Missouri Court of Appeals has indicated:

> the criteria used to determine whether a post-year event should be included in the analysis of the test year is whether the proposed adjustment is (1) 'known and measurable,' (2) promotes the proper relationship of investment, revenues and expenses, and (3) is representative of the conditions anticipated during the time the rates will be in effect.[260]

Decision

The Commission finds that the cost Spire Missouri will incur in future years resulting from the change in how costs are recovered for the use of credit or debit cards by LAC customers to pay their bills are not yet known and measurable. The Commission will utilize the level of costs calculated by Staff, which is based on actual costs incurred during the test year.

[258] Tr. 1035.
[259] Ex. 250, Kunst Surrebuttal, p. 20.
[260] *State ex rel. GTE North, Inc. v. Mo. Pub. Serv. Com'n*, 835 S.W.2d 356, 368 (Mo App. W.D. 1992).

IX. Trackers

Should LAC and MGE be permitted to implement an environmental tracker?

Findings of Fact

1. A "tracker" is a rate mechanism that tracks the amount of a specific cost of service item actually incurred by a utility and then compares that amount to the amount of an item that is currently included in a utility's rate levels. Any over-recovery or under-recovery of the item's amount set in rates is then booked to a regulatory asset or regulatory liability account, and made eligible for recovery in the utility's next general rate case proceeding through an amortization to expense.[261]

2. Spire Missouri requested authority for a tracker for its environmental compliance costs as they relate to 19 manufactured gas plant sites for which LAC and MGE may be a potential responsible party.[262]

3. During the next year, Spire Missouri may incur costs for federal, state, and local environmental compliance requirements for these gas plant sites. Spire Missouri expressed the intent to continue pursuing reimbursement for these costs from insurance companies and other potentially responsible third parties.[263]

4. Staff requested that Spire Missouri provide budgeted environmental costs for the period of 2015-2020, but Spire Missouri indicated there were no budgeted costs for expected environmental costs for MGE or LAC during that timeframe.[264] Spire Missouri projects no environmental costs will be incurred during the next two years.[265]

[261] Ex. 218, K. Lyons Rebuttal, p 2.
[262] Ex. 8, Lobser Surrebuttal, p 22.
[263] Ex. 8, Lobser Surrebuttal, p 22
[264] Ex. 218, K. Lyons Rebuttal, p.2. and Schedule KL-r1.
[265] Ex. 218, K. Lyons Rebuttal, p.2. and Schedule KL-r1.

5. Spire Missouri's requested environmental tracker would isolate for special ratemaking treatment a cost of service for which LAC and MGE are not currently incurring material costs without considering other costs that may decline and offset any environmental cost increases that may occur in the future.[266]

Conclusions of Law

A. Spire Missouri requests both LAC and MGE be authorized to track through a deferred accounting mechanism environmental costs incurred to comply with federal, state, or local environmental compliance requirements. Subsection 386.266.2, RSMo, grants the Commission the authority to approve the use of an adjustment mechanism by a gas utility in order to "reflect increases and decreases in its prudently incurred costs, whether capital or expense to comply with any federal, state, or local environmental law, regulation, or rule."

B. In determining whether an environmental tracker should be granted, Spire Missouri bears the burden of proof.[267]

Decision

Although Spire Missouri bears the burden of proof, the company failed to present evidence to support the request for an environmental tracker. No evidence was presented on the historic level of environmental costs that would demonstrate a material level of costs or that either LAC or MGE will incur, or is likely to incur, significant environmental costs that would justify the extraordinary remedy of a tracker. The Commission denies Spire Missouri's request for an environmental tracker.

---

[266] Ex. 218, K. Lyons Rebuttal, p.2
[267] *Been v. Jolly*, 247 S.W.2d 840, 854 (Mo. 1952).

X. Surveillance

Findings of Fact

1. Staff proposed a new format for surveillance data to allow more robust and separate earnings monitoring for LAC and MGE.[268]

2. Before this issue was taken up at hearing, Public Counsel, Spire Missouri, and Staff reached an agreement that Spire Missouri will provide to Staff and Public Counsel, surveillance documents for LAC and MGE separately on a quarterly basis. Those parties agreed that the information will be in the format set out by Staff.[269]

3. Public Counsel, Spire Missouri, and Staff also agreed that Spire Missouri would provide its general ledger and the Customer Care and Billing (CC&B) subledger on an annual basis, within 60 days of the close of Spire Missouri's fiscal year.

4. Additionally, as part of the agreement, Staff and Public Counsel may request copies of the general ledger and CC&B subledger on a more frequent basis than annually, if further support of the surveillance data is needed. Staff and Public Counsel agreed to first go to the company with requests to see the general ledger more frequently before making additional requests to the Commission. Spire Missouri agreed that it would provide the general ledger and CC&B subledger more frequently when requested or would provide secure access to the information.[270]

5. Public Counsel, Spire Missouri, and Staff also agreed that the information provided in the surveillance reports would be considered "confidential," and Staff agreed to follow all statutory provisions and Commission rules governing the use and protection of such confidential information.

---

[268] Ex. 205, Staff Report - Cost of Service, p. 6.
[269] Tr. 1551-52 and 1569.
[270] Tr. 1551-52.

6. The only remaining dispute on this issue involves the request by the MIEC to allow the parties to this rate case access to those same quarterly surveillance reports.

7. Staff and Public Counsel are the only parties to this case that are obligated to provide a regulatory function relating to Spire Missouri.

8. The non-regulatory parties to this case are not subject to the same statutory prohibitions on the disclosure of sensitive business information that may be contained in the surveillance reports.

Conclusions of Law

A. Staff and Public Counsel are restricted by law from divulging confidential surveillance information to any person and are subject to being guilty of a misdemeanor for violation of this law.[271]

B. Information filed in accordance with the Commission's confidentiality rule is restricted from disclosure except to attorneys and experts. Specifically, Commission rule 4 CSR 240-2.135 states in part:

> (6) Confidential information may be disclosed only to the attorneys of record for a party and to employees of a party who are working as subject-matter experts for those attorneys or who intend to file testimony in that case, or to persons designated by a party as an outside expert in that case.
>
> * * *
>
> (13) All persons who have access to information under this rule shall keep the information secure and may neither use nor disclose such information for any purpose other than preparation for and conduct of the proceeding for which the information was provided. This rule shall not prevent the commission's staff or the Office of the Public Counsel from using

[271] Section 386.480, RSMo.

confidential information obtained under this rule as the basis for additional investigations or complaints against any public utility.

C. Staff and Public Counsel are the only parties to this case that are obligated to provide a regulatory function relating to Spire Missouri.

D. The non-regulatory parties to this case are not subject to the same statutory prohibitions on the disclosure of sensitive business information that may be contained in the surveillance reports.

Decision

The Commission finds that it is reasonable to adopt the agreement of Spire Missouri, Staff, and Public Counsel regarding surveillance. The Commission will order Spire Missouri to provide Staff and Public Counsel the surveillance data in the format agreed upon and set forth in Attachment 1 of *Staff's Initial Post-Hearing Brief* on a quarterly basis. Additionally, the Commission will order Spire Missouri to provide Staff and Public Counsel its general ledger and CC&B subledger on an annual basis, within 60 days of the close of Spire Missouri's fiscal year, and to make both the ledger and subledger available more frequently in the event further support of the surveillance data is needed.

The Commission rejects the request of MIEC to provide surveillance reports to the nonregulatory parties to this case. Unlike the Staff and Public Counsel, the other parties, specifically the industrial consumers, are not obligated to provide any regulatory function relating to Spire Missouri. Further, the non-regulatory parties to this case are not subject to the same statutory prohibitions on the disclosure of sensitive business information that may be contained in those reports.

The Commission previously determined that the parties to this case had an interest sufficient to allow their participation and different from the interest of the general public. However, outside the context of a formal proceeding, the Commission cannot know that the interests of each of these parties will continue. Further, outside the context of a formal proceeding where the Commission has determined that a party has an interest in the case, enforcing the Commission's confidentiality rule becomes impossible. Therefore, the Commission denies MIEC's request.

XI. Rate Design

A. Should a Revenue Stabilization Mechanism or other rate adjustment mechanism be implemented for the Residential and SGS classes for MGE and LAC? If so, how should it be designed and should an adjustment cap be applied to such a mechanism?

B. Reflective of the answer to part A, should LAC's weather mitigated Residential Rate Design be modified to collect a customer charge and variable charge for all units of gas sold, or should it be continued in its current form?

C. Weather Normalization Adjustment Rider (WNAR) Tariff – should a WNAR be adopted? If so, what modifications to Staff's proposed tariff should be adopted?

Findings of Fact

1. After the Commission determines the amount of revenue necessary, it must decide how that revenue will be spread among Spire Missouri's customer classes via rates. The process of determining how Spire Missouri's non-gas revenue requirement will be allocated among the different customer classes is known as rate design.[272]

2. A non-unanimous stipulation and agreement with no objections is

[272] Ex. 209, Staff Report - Class Cost of Service, p. 11.

approved in this order and addresses the class cost of service and rate design issues with the exception of the residential customer charge and rate structure, and the revenue stabilization mechanism (RSM) or other tariffed rate adjustments. [273]

3. This case was unique in that it is the first instance that a RSM for weather and/or conservation was proposed under Section 386.266.3, RSMo.

4. Spire Missouri seeks a RSM that would appear as a separate charge on the customer bills and would vary in response to changes in average customer usage.[274]

5. Spire Missouri argues that a RSM is an appropriate rate design because most fixed costs do not increase with increased usage, tying recovery of fixed costs to customer usage discourages the company from pursuing energy efficiency programs, and the volumetric rate sometimes has the unintended consequence of allowing over-recovery during periods of high usage. Spire Missouri further argues that a RSM would simplify rate designs and would provide residential and commercial customers with more stability in their bills.[275]

6. LAC and MGE confirmed that historically, they have fully recovered their operating expenses, interest payments, depreciation expense, and income taxes.[276]

7. A RSM is not needed by Spire Missouri due to difficulty meeting its revenue requirement without a RSM.[277]

8. It is difficult to design a RSM that will distinguish lower usage due to

[273] *Nonunanimous Stipulation Regarding Revenue Allocation and Non-Residential Rate Design* (filed December 20, 2017).
[274] Ex. 238, Stahlman Rebuttal, p. 5.
[275] Ex. 14, T. Lyons, Surrebuttal, pp. 3-4.
[276] Ex. 753, Meyer Rebuttal, p. 22.
[277] Tr. 2359.

economic conditions versus lower usage due to conservation.[278]

9. The RSM proposed by Spire Missouri adjusts for *all changes* in average customer use, not only due to variations in weather and/or conservation.[279] It would adjust rates for the effects of fuel switching, rate switching, new customers with non-average usage, and economic factors.[280] For example, if Spire Missouri was to add low usage customers in place of current high usage customers, the RSM would treat their usage as too low and would make a rate adjustment allowing the company to recover the difference between those new customers' lower-than-average usage and an average customer's usage.[281] Additionally, if a large Small General Service (SGS) customer that acts more like a Large General Service (LGS) customer moved to an LGS rate, the overall average usage of the SGS class would decrease, the RSM would provide the company with additional compensation even though there was no change in actual total usage.[282]

10. The RSM proposed by the companies would not provide rate stability because of the numerous tariff changes per year. As proposed, the RSM would have up to four rate changes per year and an annual true-up.[283]

11. With a volumetric rate, the goal of the companies to increase revenues by selling more gas is misaligned with the goal of conservation for customers. This misalignment is best resolved by using Staff's climatic normal and weather normalization because annual natural gas usage is 95 percent correlated with annual

---

[278] Tr. 2326.
[279] Ex. 238, Stahlman Rebuttal, p. 6; and Ex. 15, Weitzel Direct, p. 21..
[280] Ex. 238, Stalhman Rebuttal, p. 6.
[281] Ex. 238, Stahlman Rebuttal, p.8 and Sch. MLS-r-2; and Ex. 260, Stalhman Surrebuttal, p. 6.
[282] Ex. 238, Stalhman Rebuttal, p. 8; and Ex. 260, Stahlman Surrebuttal, p. 6.
[283] Ex. 753, Meyer Rebuttal, p. 23.

heating degree days (HDD).[284]

12. Weather variations cause the greatest variations in revenues for the companies.[285]

13. Based on Staff's weather normalization regressions, a mechanism based solely on weather could account for over 97 percent of usage variation within a given year.[286] Thus, a weather normalization adjustment rider would account for most of the variations due to weather.

14. During the hearing, Staff presented a sample tariff sheet with a Weather Normalization Adjustment Rider (WNAR) for Commission consideration.[287] That sample tariff sheet, which was admitted into the record as Exhibit 281, included a method of adjusting rates based only on weather variations.[288] No objection to the document was made, with the exception of proposed modifications submitted by Spire Missouri.[289]

15. Spire Missouri proposed that if the Commission were to reject its RSM and instead adopt the WNAR, three modifications should be made:

- Approve the WNAR for both LAC's and MGE's Residential and Small General Service Classes.
- Eliminate the $0.01 per therm (or ccf) limit on adjustments that can be made. If the Commission determines that some limit is appropriate, it should be: (1) a limit only on ***upward*** adjustments and (2) that it be set at $0.05 per therm or ccf. Additionally, provide that any adjustment amounts falling outside the $0.05 limit would be deferred for recovery from customers in the next WNAR adjustment.

---

[284] Ex. 260, Stahlman Surrebuttal, pp. 4-5 and 9. (A "heating degree day" is a formula for capturing how hot or cold it is and is used in the weather normalization process of rate cases. Tr. 2434.)
[285] Ex. 753, Meyer Rebuttal, p. 23.
[286] Ex. 238, Stahlman Rebuttal, p. 10.
[287] Ex. 281, Sample WNAR Tariff Sheet.
[288] Tr. 2433-2434.
[289] Ex. 63, Affidavit Regarding Weather Normalization Adjustment Rider.

- Allow for at least three adjustments per year, including the annual required one, provided that there must be at least 60 days between each adjustment.

16. Changing the $0.01 per therm (or ccf) limit on adjustments in the WNAR sample tariff to a limit of $0.05 per therm (or ccf) on *upward* adjustments will ensure that any monthly increase for the average customer will not be so high as to provide rate shock while providing customers with an opportunity to receive a larger monthly decrease if the weather is exceptionally cold.[290] Additionally, by providing that any adjustments falling outside the $0.05 limit will be deferred for recovery from customers in the next WNAR adjustment, the company is assured of receiving the appropriate revenue. Further, these changes are consistent with and can be administered in a similar manner to the PGA/ACA clauses in the LAC and MGE current tariffs.

17. The WNAR proposed in Exhibit 281 when modified according to Spire Missouri's second suggested modification set out above is a just and reasonable mechanism to account for weather variations.

18. With regard to the application of the WNAR to the Small General Services (SGS) customers, unlike residential customers, there is no established coefficient[291] for the relationship between weather and usage for SGS customers.[292] Additionally, "rate switchers"[293] are a common occurrence for LAC.[294] Larger

[290] Ex. 63, Affidavit Regarding WNAR, p. 2.
[291] "Correlation is a measure of how the variations in one dataset are consistent with the variations in another. A correlation coefficient is a number between -1 and +1 calculated so as to represent the linear dependence of two variables or sets of data. Generally speaking, the closer a correlation coefficient is to 1, the more the datasets vary consistently with each other. If the correlation is negative, the variation in one dataset gets more positive as the variation in the other dataset gets more negative. Conventionally, if a correlation coefficient is greater than 0.7 then it is interpreted that there is a strong positive relationship." (Staff Report, p. 97, fn. 47.)
[292] Ex. 205, Staff Report - Cost of Service, pp. 97-98
[293] Rate switching is when customers switch which rate class they will be served on during the test year or

customers are less weather sensitive than smaller customers because they use gas all year round for more than just heating.[295] Without knowing the final makeup of the customers in the SGS class, it is impossible to calculate an unbiased coefficient for the SGS class. Therefore, it is not just and reasonable to adopt this proposed modification.

19. Staff's proposal limits the rate adjustments to two per year, thus including half of a heating and cooling season. This would account for customers who have limited seasonal usage (e.g. heat water only). A triannual filing as proposed by the company would cause one period to include either a majority of summer or of winter months where a majority of the changes would occur. For these reasons, this modification is not just and reasonable.

Conclusions of Law

A. The Commission's powers are "limited to those conferred by the statutes."[296]

B. A RSM is authorized by Subsection 386.266.3, RSMo, which provides:

> Subject to the requirements of this section, any gas corporation may make an application to the commission to approve rate schedules authorizing periodic rate adjustments outside of general rate proceedings to reflect the non-gas revenue effects of increases or decreases in residential and commercial customer usage due to variations in either weather, conservation, or both.

C. The statue authorizes an RSM that allows adjustments for variations due

update period. (Ex. 205, Staff Report - Cost of Service, p. 97)
[294] Ex. 205, Staff Report - Cost of Service, pp. 90-99.
[295] Tr. 2569.
[296] *State ex. Rel. Utility Consumers Council of Missouri v. Public Service Commission,* 585 S.W.2d 41, 49 (Mo. 1979).

to *weather, conservation, or both*. The Commission cannot approve Spire Missouri's proposed RSM because the RSM would make adjustments for all variations in average usage per customer (such as, fuel switching, rate class switching, new customers with non-average usage, and economic factors) and not just those limited to weather or conservation.

Decision

Spire Missouri has not provided evidence that the RSM it proposed is needed for either revenue recovery (Spire Missouri has had no difficulty in meeting its revenue requirement) or to incentivize conservation. Further, the RSM as proposed by Spire Missouri is not consistent with the statutory requirements that allow the Commission to approve a mechanism for adjusting rates outside of a general rate proceeding "to reflect the non-gas revenue effects of increases or decreases in residential and commercial customer usage due to variations in either weather, conservation, or both"[297] because it would adjust rates for *all changes* in average customer use, not only due to variations in weather and/or conservation. However, because annual natural gas usage is 95 percent correlated with annual HDD, using Staff's climatic normal and weather normalization in the form of the WNAR tariff would more accurately resolve the revenue stabilization issue because it is specifically linked to weather fluctuations.

The Commission further finds that the $0.01 per therm (or ccf) limit on adjustments under the WNAR tariff as proposed by Staff should be eliminated but that a limit of $0.05 per therm (or ccf) on upward adjustments should be included. This will ensure that any monthly increase for the average customer will not be so

[297] Subsection 386.266.3, RSMo.

high as to create rate shock, while providing customers with an opportunity to receive a larger monthly decrease if the weather is exceptionally cold. The WNAR tariff shall also provide that any adjustments falling outside the $0.05 limit will be deferred for recovery from customers in the next WNAR adjustment. Thus, this mechanism becomes similar to the PGA/ACA process with regard to adjustments and a true-up period.

The Commission rejects the other two modifications to the WNAR that Spire Missouri proposed. The Commission will not order the WNAR to apply to the SGS classes because no coefficient has been established for the relationship between weather and usage and "rate switchers" seem to be a common occurrence for LAC. It is often assumed that the larger customers are less weather sensitive than smaller customers. Without knowing the final makeup of the customers in the SGS class, it is impossible to calculate an unbiased coefficient for the SGS class. Additionally, the Commission rejects Spire Missouri's request to allow three rate adjustments per year. Staff's proposal limits the rate adjustments to two per year, thus including half of a heating and cooling season. This would account for customers who have limited seasonal usage (e.g. heat water only). A triannual filing as proposed by the company, however, would cause one period to include either a majority of summer or of winter months where a majority of the changes would occur. Thus, the triannual filing would make the customer billing more volatile than Staff's proposal.

The Commission determines that a RSM as proposed by Spire Missouri is not necessary for the company because the utility is not having any difficulty meeting its revenue requirement and has not been shown to be a good mechanism to incentivize conservation. Further, the RSM as proposed is not authorized by the statute. Therefore, the Commission rejects Spire Missouri's proposed RSM. However, the Commission also determines that a WNAR tariff is in the public interest and is just and reasonable as set out by the Staff's example tariff with the modification of an upward adjustment limit and elimination of a downward adjustment limit.[298] Spire Missouri shall include the WNAR tariff with a limit of $0.05 per therm (or ccf) on upward adjustments and shall provide that any adjustments falling outside the $0.05 limit will be deferred for recovery from customers in the next WNAR adjustment.

D. What should the Residential customer charge be for LAC and MGE, and what should the transition rates be set at until October 1, 2018?

<u>Findings of Fact</u>

1. The customer charge is the set amount on every customer's bill that must be paid even if the customer uses no gas.

2. Customer-related costs are the minimum costs necessary to make gas service available to the customer, regardless of how much gas the customer uses. Examples include meter reading, billing, postage, customer account service, and a portion of the costs associated with required investment in a meter, the service line, and other billing costs. Customer-related costs are generally recovered through the customer charge while other costs are recovered through volumetric rates that vary with the amount of gas used.[299]

3. It is important to remember that determining an appropriate customer

[298] Ex. 281, Sample WNAR Tariff Sheet.
[299] Ex. 505, Hyman Rebuttal, pp. 9-10.

charge is a question of rate design, not a question of the company's revenue requirement. That means any increase in the company's customer charge would be accompanied by a decrease in volumetric rates so that, in theory, the company recovers the same amount of revenue.

4. In actual practice, because the amount collected from volumetric rates varies with the amount of gas used, the company will collect less money from volumetric rates when customers use less gas. Thus, for example, in the summer, when customers are using less gas for heating, the company runs the risk of collecting less revenue. However, a higher customer charge also creates the problem of customers dropping off the system seasonally.

5. A lower customer charge coupled with a volumetric rate encourages efficient consumption because higher usage causes higher bills.[300]

6. A lower customer charge can also help low-income customers, because they tend to use less natural gas than the general body of residential customers.[301]

7. LAC's current residential rate consists of a customer charge of $19.50 and a seasonal volumetric charge of $0.91686 per therm for the first 30 therms used in the winter, but no charge for therms used after 30 in the winter; $0.31290 per therm for the first 30 therms in summer; and $0.15297 for all therms over 30 in the summer. LAC's current "weather mitigated" rates result in a flat customer charge of $47.01 ($19.50 plus $0.91686 per therm) for virtually every residential customer in the winter months.[302]

8. MGE's current residential rate consists of a $23.00 customer charge and a

[300] Ex. 505, Hyman Rebuttal, pp. 10, 11, and 13-15.
[301] Ex. 503, Kroll Direct, pp. 21-23.
[302] Ex. 209, Staff Report - Class Cost of Service, p. 20.

flat volumetric rate of $0.07380 per ccf used.[303]

9. A class cost of service study (CCOS) provides a basis for allocating and/or assigning to the customer classes a utility's cost of providing service to all customer classes in a manner that best reflects cost causation.[304]

10. Staff performed a separate CCOS for LAC and MGE.[305] Staff's CCOS for both LAC and MGE were primarily based on cost.[306] Staff's class cost of service studies showed that on a strict cost allocation basis, the customer charge should be approximately $26.00 per customer for LAC and $17.01 for MGE.[307]

11. Staff included the following costs in the calculation of the residential customer charge:

- Distribution - services (investment and expenses)
- Distribution - meters and regulators (investment and expenses)
- Distribution - customer installations
- Customer deposits
- Customer billing expenses
- Uncollectible accounts (write-offs)
- Customer service & information expenses
- Portion of income taxes[308]

12. For LAC, Staff recommended an increased customer charge of $26.00 and recommended charging customers for all therms including therms used after 30.[309] Alternatively, Staff presented an inclining block residential rate design for LAC with a $26.00 customer charge and a volumetric charge per therm to increase for usage beyond 50 therms.[310] As a further alternative to decrease the customer charge, Staff

[303] Ex. 209, Staff Report - Class Cost of Service, p. 20.
[304] Ex. 209, Staff Report - Class Cost of Service, p. 2.
[305] Ex. 209, Staff Report - Class Cost of Service, p. 1.
[306] Ex. 236, R. Kliethermes Rebuttal, p. 6.
[307] Ex. 209, Staff Report - Class Cost of Service, p. 20.
[308] Ex. 209, Staff Report - Class Cost of Service, p. 20.
[309] Ex. 209, Staff Report - Class Cost of Service, pp. 14 and 20.
[310] Ex. 209, Staff Report - Class Cost of Service, p. 24.

presented a design for LAC consisting of a customer charge of $22.00 plus a flat volumetric rate, and an alternative inclining block residential rate design with a $22.00 customer charge and a volumetric charge per them to increase for usage beyond 50 therms.[311]

13. For MGE, Staff recommended a customer charge of $20.00, plus a flat volumetric rate per ccf.[312] Alternatively, Staff presented an inclining block residential rate design for MGE with a $20.00 customer charge and a volumetric charge per ccf to increase for usage beyond 50 ccf.[313]

14. Although Spire Missouri filed a CCOS, its proposed residential customer charge is not really based on its study. Rather, those proposed customer charges were designed to be in alignment with the RSM proposal.[314]

15. Public Counsel proposed a customer charge of $14.00 for both LAC and MGE.[315]

16. DE supported lower customer charges, but did not provide evidence related to a specific charge.[316] DE also supported a lower tail-block rate for LAC customers during the winter. This rate would apply only to the upper five percent of usage during the winter to decrease the effects of a cold winter.[317]

17. Raising the fixed customer charge to recover all of the fixed costs, such as Staff's proposed $26.00 customer charge for LAC, can cause rate shock for customers

[311] Ex. 284, Inclining Block Rate Document.
[312] At the time Staff filed its Class Cost of Service Report, the volumetric rate was calculated to be $0.13859 per ccf. However, the volumetric component of the rates for both MGE and LAC will change based on the revenue requirement outcome of these cases and the billing determinants stipulated to after the filing of Staff's CCOS Report. (Ex. 209, p. 14).
[313] Ex. 209, Staff Report - Class Cost of Service, p. 23.
[314] Ex. 236, R. Kliethermes Rebuttal, p. 5.
[315] Ex. 249, R. Kliethermes Surrebuttal, p. 8.
[316] Ex. 249, R. Kliethermes Surrebuttal, p. 8.
[317] Ex. 505, Hyman Rebuttal, pp. 16-17 and 23.

least able to afford the service.[318]

18. An inclining block rate is a volumetric rate where the customers pay more per unit of energy consumed at the higher levels of usage. An inclining block rate can encourage energy efficiency.[319]

19. LAC and MGE customers' usage is very seasonal with 90 percent of the customers using less than 20 therms in the summer months.[320] Further, approximately 95 percent of the change in residential customer usage is due to weather.[321]

20. Customers are concerned about higher customer charges as evidenced by the numerous oral and written comments received at local public hearings saying the customer charges were too high.[322]

21. The Commission is not bound to set the customer charges based solely on the details of the cost of service studies. The Commission must also consider the public policy implications of changing the existing customer charges. There are strong public policy considerations in favor of lower customer charges.

22. Residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less gas, either for economic reasons or because of a general desire to conserve. A lower customer charge gives the customer the opportunity to conserve where appropriate. However, during the winter, conservation becomes much more difficult because the majority of the usage is for heating the home. A level block rate will give the customers some stability during the winter when they are less able to conserve. An inclining block

[318] Ex. 505, Hyman Rebuttal, pp. 17-18.
[319] Ex. 505, Hyman Rebuttal, pp. 17-18.
[320] Ex. 260, Stahlman Surrebuttal, p. 8.
[321] Ex. 260, Stahlman Surrebuttal, p. 9.
[322] Ex. 505, Hyman Rebuttal, pp. 4-8; and Tr. 2359-2360.

rate in the summer coupled with a lower customer charge will give the customers the ability to achieve savings through conservation during the time when their usage is not critical to heating the home.

Conclusions of Law

The Commission makes no additional conclusions of law for this issue.

Decision

The Commission finds that Spire Missouri's customer charges for LAC should be $22.00 and for MGE should be $20.00 with an inclining block rate in the summer and a level block rate in the winter for both. An inclining block rate in the summer will incentivize conservation when the customers have the most control over usage not necessary to heat their homes. Additionally, the level block in the winter will provide stabilization for customers during the winter months when they have more difficulty paying increased bills in order to heat their homes. These rates shall be calculated based on the agreed to billing determinants and the revenue requirement set out in this order in the method set out in Staff Exhibit 284.

XII. Pensions, OPEBs and SERP

A. What is the appropriate amount of pension expense to include in base rates?

Findings of Fact

1. This issue deals with the amount of funding or pension expense for MGE and LAC's pension assets that should be reflected in rates.

2. Spire Missouri is proposing to include $31 million in rates for contributions to the LAC pension plan.[323] This is designed to fund 90 percent of pension liabilities for LAC.[324] Public Counsel and the Union support this level of funding.[325]

3. Pension Benefit Guarantee Premiums (PBGC) is a federal agency created by the Employee Retirement Income Security Act (ERISA) that provides a form of insurance to protect pension benefits in the event of a default by a sponsor of a pension plan.[326]

4. Funding of pension liabilities at the level proposed by Spire Missouri will lower the PGBC premiums in the future and prevent further significant increase in the pension asset.[327] Each $1,000 paid in pension expense by LAC will reduce PBGC premiums by $34.00.[328]

5. Staff recommends funding LAC's pension at the 80 percent ERISA minimum level which is $29 million for LAC.[329]

6. ERISA minimums are premised on pension trusts earning a sufficient amount of return on investment in the future, thus eliminating the need for additional funding.[330]

7. Spire Missouri, Staff, and Public Counsel agree that the pension expense for MGE should be $5.5 million.[331]

---

[323] Ex. 20, Buck Rebuttal, p. 9.
[324] Ex. 20, Buck Rebuttal, p. 9.
[325] *Initial Brief of the Office of the Public Counsel,* p. 37.
[326] Ex. 231, Young Rebuttal, p. 4.
[327] Ex. 263, Young Surrebuttal, p. 2.
[328] Ex. 231, Young Rebuttal, p. 6.
[329] Ex. 231, Young Rebuttal, p. 4.
[330] Ex. 231, Young Rebuttal, p. 2.
[331] Ex. 20, Buck Rebuttal, p. 11; *Staff's Initial Post-Hearing Brief* (filed January 9, 2018), p. 65; and *Office of the Public Counsel's Reply Brief* (filed January 17, 2018), p. 26.

8. Public Counsel also requests that the Commission order a strategic financing review of the pension and benefit plans.[332]

9. LAC's pension plans already receive much "scrutiny and utilize some of the nations' leading investment advisory and actuarial firms to assist it in planning."[333]

10. In the past, the Commission has investigated the pension plan practices of all the utilities in the state and found no shortcomings with regard to LAC's pensions.[334]

Conclusions of Law

The Commission makes no additional conclusions of law on this issue.

Decision

The pension asset of LAC has grown quite large and a 90 percent funding level would lower PGCB premiums in the future and prevent the regulatory asset from increasing in size substantially. However, a 90 percent funding level would require an additional $2 million in pension expense, thus, raising rates. Additionally, the ERISA minimums are calculated to take into consideration growth of the funds through returns, thus, additional investment may not be needed. In balancing the needs of the ratepayers to keep rates from increasing, with the need Spire Missouri to fulfill its pension obligations, the Commission determines that an 80 percent ERISA funding level ($29 million) for LAC is the most just and reasonable level.

With regard to MGE's pension asset funding, Spire Missouri, Staff, and Public Counsel reached consensus that the funding level should be $5.5 million. Having reviewed the evidence before it, the Commission determines that $5.5 million is a just

[332] Ex. 408, Pitts Direct, p. 17.
[333] Ex. 20, Buck Rebuttal, p. 11; and Tr. 2087.
[334] Ex. 20, Buck Rebuttal, p. 11.

and reasonable funding level for MGE's pension expense.

Public Counsel also requested that the Commission order a strategic financing review of the pension and benefit plans. The Commission was not persuaded that such a review is necessary since Spire Missouri's pension and benefit plans already receive scrutiny and utilize investment advisory and actuarial firms to assist it in planning. Additionally, in the past the Commission has investigated the pension plan practices of all the utilities in the state and found no shortcomings with regard to LAC's pensions. The Commission will not order a review of the pension and benefit plans.

B. What is the appropriate amount of the LAC and MGE pension assets?

<u>Findings of Fact</u>

1. This issue is about what amount to use for regulatory purposes as the total of LAC's prepaid pension asset and MGE's prepaid pension liability.

2. The pension asset is a regulatory asset that represents liabilities owed by ratepayers for LAC's and MGE's contributions to the company pension funds that have not been recovered in rates.[335] A pension liability, is the opposite. That is, a liability is created when the company has collected more from ratepayers than it has paid (with regard to the authorized regulatory payments) into the pension funds.

3. Staff, MGE, and Public Counsel agree that MGE currently has a pension *liability* of $28.4 million.[336] With regard to LAC, however, there is not agreement.

4. The prepaid pension asset is equal to the difference between cash

[335] Ex. 20, Buck Rebuttal, p. 9.
[336] Ex. 286, Staff True-Up Accounting Schedule 02 — MGE, p. 1.

contributions to the pension trust and cash collected in rates since October 1, 1987.[337] The LAC pension asset amount has not been fully litigated for over 20 years. Staff and LAC agree that approximately $131.4 million has accumulated in LAC's pension asset since 1996.[338] However, the disagreement comes down to how much customers paid in rates for pension expense between 1990 and 1994 for both FAS 87 and FAS 88 accounts, and from 1994 to 1996 for the FAS 88 account.

5. LAC argues that between the time it adopted FAS 87 in 1987 and its rate case in 1994, its pension asset accumulated $19.8 million; and between that 1994 rate case and its 1996 rate case an additional $9.0 million accumulated under FAS 88. Thus, LAC argues that its prepaid pension asset is $28.8 million more than Staff's position.

6. Staff's witness, Matthew Young, did a thorough and credible review of prior testimony and workpapers in LAC rate cases during the relevant period.[339] The Commission adopts many of Mr. Young's findings as follows:

a. Pension expense is an item that is examined and adjusted in every large rate case.[340] Until the current case, however, LAC had not written testimony responsive to Staff's adjustment to LAC's prepaid pension asset.[341]

b. LAC has not sought to include a pension asset in rate base in any rate case since 1987.[342]

c. In LAC's various rate cases between October 1, 1987 and

[337] Tr. 2074.
[338] Ex. 285, Staff True-Up Accounting Schedule 02 – LAC, p. 1.
[339] Ex. 263, Young Surrebuttal, p. 9.
[340] Ex. 263, Young Surrebuttal, p. 13.
[341] Ex. 263, Young Surrebuttal, p. 11.
[342] Ex. 263, Young Surrebuttal, p.8.

September 1, 1994, neither LAC nor Staff itemized a pension asset in rate base in their accounting schedules.[343]

d. A prepaid pension asset was first proposed to be included in rate base by LAC in Case No. GR-96-193. In that case, LAC witness Waltermire supported a prepaid pension asset in LAC's rate base.[344]

e. LAC did not seek to include in its rate base all costs deferred after the 1987 implementation of FAS 87.[345]

f. Based on the testimony presented in Case No. GR-96-193, including Staff witness Gibbs's direct testimony, both Staff and LAC were in agreement on the methodology to calculate the prepaid pension asset created by the adoption of FAS 87.[346]

g. LAC changed the methodology it used to calculate the rate base effect of the prepaid pension asset in its next rate case, Case No. GR-98-374. This is shown in the direct testimony in that case of LAC witness Fallert (then employed as the Controller of LAC) implying that LAC no longer calculated its pension asset beginning on September 1, 1994.[347]

h. In LAC's next rate case, Case No. GR-98-374, the direct testimony of Staff witness Traxler shows that Staff continued to calculate LAC's prepaid pension asset beginning with September 1, 1994, consistent with both parties' calculations in Case No. GR-96-193.[348]

---

343 Ex. 263, Young Surrebuttal, p. 8.
344 Ex. 263, Young Surrebuttal, p. 9.
345 Ex. 263, Young Surrebuttal, p. 9.
346 Ex. 263, Young Surrebuttal, p. 9.
347 Ex. 263, Young Surrebuttal, pp. 10-11; citing, Fallert Direct, p. 10, lns. 16-23, in Case No. GR-98-374.
348 Ex. 263, Young Surrebuttal, pp. 10-11; citing, Traxler Direct, p. 22, lns. 22 -23 through p. 23, lns. 1-8, in Case No. GR-98-374.

i. LAC changed the methodology it used to calculate the rate base effect of the prepaid pension asset in Case No. GR-98-374. However, Staff has maintained the adjustment to the booked asset in every LAC rate case since Case No. GR-94-220.[349]

j. LAC adopted FAS 87 for financial reporting purposes in 1987. However, FAS 87 was not used for regulatory purposes prior to the effective date of rates in Case No. GR-94-220.[350]

k. Additionally, in Case No. GR-92-165, LAC's rate case immediately prior to the 1994 case, both Staff and LAC filed direct testimony supporting the use of cash contributions to set pension expense. Since Staff and LAC had the same methodology, and other parties did not present a different position, it is likely rates were set using the current level of cash contribution instead of FAS 87 expense.[351]

l. The testimony of Staff witness Gibbs in Case No. GR-96-193 refutes LAC's contention that during the period prior to September 1, 1994, FAS 88 was also used for setting rates.[352]

7. Prior to September 1, 1996, when rates from Case No. GR-96-193 became effective, accumulated pension assets in FAS 88 were not included in LAC's cost of service.[353]

8. Public Counsel agrees with Staff's calculation of the prepaid pension asset, with the exception that it believes Laclede's contributions in excess of the

[349] Ex. 263, Young Surrebuttal, p. 11.
[350] Ex. 205, Staff Report - Cost of Service, p. 67.
[351] Ex. 263, Young Surrebuttal, pp. 13-14.
[352] Ex. 263, Young Surrebuttal, pp. 15-16.
[353] Ex. 205, Staff Report - Cost of Service, p. 67.

minimum required by ERISA should not be included in rate base. Public Counsel argues that LAC has overstated its ERISA minimums and, therefore, should not be allowed to use an exception in a previous stipulation and agreement to over-contribute to the pension asset. Thus, Public Counsel recommends a reduction in the value of the prepaid pension asset of approximately $54 million.[354]

9. Public Counsel's witness admitted that his calculations of the contributions in excess of ERISA minimums were possibly overstated.[355]

10. LAC has a collective bargaining agreement with its Union employees that it will offer those employees the option of a lump sum payment at retirement.[356]

11. LAC has made contributions in excess of ERISA minimums. These contributions were made to avoid benefit restrictions of the Pension Protection Act and to avoid variable premiums of PBGC.[357]

Conclusions of Law

A. Paragraph 7 of the Commission-approved Stipulation and Agreement from LAC's rate case, Case No. GR-2013-0171, states that LAC shall be allowed rate recovery for contributions it will make to avoid benefit restrictions specified by the Pension Protection Act of 2006 (PPA).[358] LAC contributed funds sufficient to avoid the restrictions outlined in the PPA.

B. Additionally, the Commission-approved Stipulation and Agreement in LAC's rate case, Case No. GR-2013-0171, also states that LAC can include in the

[354] Ex. 413, Pitts Rebuttal, p. 4.
[355] Ex. 413, Pitts Rebuttal, p. 4.
[356] Tr. 2080.
[357] Tr. 2080-2081.
[358] Ex. 263, Young Surrebuttal, p. 8; Ex. 413, Pitts Rebuttal, p. 4; Ex. 20, Glen Buck Rebuttal, Schedule GWB-R2, p. 8; and Tr. 2084 and 2096.

pension asset contributions in excess of ERISA minimums as they were made to avoid variable premiums from the PBGC.[359]

C. One benefit restriction is the inability to offer a lump sum payment option to retirees. In order to avoid this restriction, the pension fund has to be funded by at least 80 percent of ERISA minimums.[360]

Decision

The Commission was persuaded by Staff's thoughtful and logical review of the supporting testimony from the period at issue as set out in the findings above. That testimony shows that parties were using a cash contribution method, and not FAS 87 or FAS 88 accrual accounting for ratemaking purposes. The Commission finds the sworn testimony of LAC and Staff witnesses that were knowledgeable of the issue during the era in question to be more persuasive than the conclusions drawn by LAC more than 20 years later.

Further, Public Counsel's evidence quantifying excess contributions was not reliable. Therefore, the Commission denies Public Counsel's adjustment for pension contributions over the ERISA minimums.

After reviewing the evidence, the Commission determines that the amount of MGE's pension *liability* is $28.4 million.[361] The Commission further determines that the appropriate amount of the LAC prepaid pension asset is approximately $131.4 million as set out by Staff.[362]

---

[359] *Order Approving Unanimous Stipulation and Agreement*, File No. GR-2013-0171 (issued June 26, 2013), attachment *Stipulation and Agreement*, para. 7; See also, Ex. 20, Glen Buck Rebuttal, Schedule GWB-R2.
[360] *e.g.* 26 USC 436 (d)(5) and (3)(a) and 29 USC 1056 (g)(3)(A) and (C)(I); *See also*, 26 C.F.R. § 1.436-1.
[361] Ex. 286, Staff True-Up Accounting Schedule 02 — MGE, p. 1.
[362] Ex. 285, Staff True-Up Accounting Schedule 02 – LAC, p. 1.

C. How should the pension regulatory assets be amortized?

Findings of Fact

1. Staff recommended an eight-year amortization of the prepaid pension asset while the company originally proposed a ten-year amortization.

2. LAC indicated that it was not opposed to Staff's proposal.[363]

3. Public Counsel originally proposed a twenty-year amortization[364] but has since agreed to the eight-year amortization as well.[365]

4. Thus, the only parties to file testimony on this issue agree to an eight-year amortization period.

Conclusions of Law

The Commission makes no additional conclusions of law on this issue.

Decision

The parties filing testimony on this issue have reached consensus that the prepaid pension asset should be amortized over eight years. The Commission finds that eight years is a reasonable amount of time to amortize the pension regulatory asset.

[363] Ex. 20, Buck Rebuttal, p. 9.
[364] Ex. 408, Pitts Direct, p. 17.
[365] *Initial Brief of the Office of the Public Counsel,* p. 39.

D. What is the appropriate amount of SERP expense to include in base rates?

Findings of Fact

1. The Supplemental Executive Retirement Plan (SERP) is an employee benefit fund for highly compensated employees and employees that defer a portion of their income as set out by Section 415 of the Internal Revenue Code.[366]

2. SERP applies to executives and non-executive employees of Spire Missouri.[367]

3. Staff has calculated the SERP expense as $468,731 based on a three-year average.[368] Spire Missouri is in agreement with that amount.[369]

4. Public Counsel's position is that a normalized annual SERP payment of $24,097 is the appropriate amount to include for SERP expense.[370]

5. Public Counsel argued that lump sum payments are erratic, nonrecurring, and difficult to predict and thus are not known and measurable.[371]

6. Upon retirement, Spire employees receiving SERP have the option of an annuity or a lump sum SERP payment. With only one or two exceptions, most employees choose the lump sum payment.[372]

7. Staff examined actual historical data for SERP payments from 2010 through 2016. The historical data shows that lump sum payments can be reasonably expected to recur.[373]

---

[366] 26 U.S.C.A. § 415; and Tr. 2215.
[367] Tr. 2215.
[368] Ex. 296, Staff Updated True-Up Accounting Schedules-LAC; and Ex. 297, Staff Updated True-Up Accounting Schedules-MGE.
[369] Tr. 2219.
[370] Ex. 425, Hyneman Surrebuttal, p. 38.
[371] Ex. 425, Hyneman Surrebuttal, p. 33-36.
[372] Tr. 2213-2214.

8. Staff excluded one lump sum payment from its averages because this SERP payment was for the departure of a CEO and was unusually large. The departure of a CEO, and thus, a payment this large, is not expected to recur.[374]

9. Further, when a historical average is used, with the exclusion of any special anomalies, the size of lump sum SERP payments is not volatile.[375]

10. Lump sum SERP payments for Spire Missouri are known and measurable.

Conclusions of Law

A. The Missouri Court of Appeals has stated:

> the criteria used to determine whether a post-year event should be included in the analysis of the test year is whether the proposed adjustment is (1) 'known and measurable,' (2) promotes the proper relationship of investment, revenues and expenses, and (3) is representative of the conditions anticipated during the time the rates will be in effect.[376]

Decision

Historical data shows that with regard to Spire Missouri's SERP expense, lump-sum payments can be reasonably expected to recur. In fact, with only a few exceptions, retiring employees opt to receive their SERP benefits by a lump sum payment instead of by annuity. Further, when considering the historical averages, and excluding the one anomaly of an especially high payment, the size of the lump sum SERP payments is not volatile and is known and measurable. The Commission finds that the appropriate amount of SERP expense is $468,731 as calculated by Staff.

[373] Ex. 263, Young Surrebuttal, p. 21.
[374] Ex. 263, Young Surrebuttal, p. 21.
[375] Ex. 263, Young Surrebuttal, pp. 21-22.
[376] *State ex rel. GTE North, Inc. v. Mo. Pub. Serv. Com'n*, 835 S.W.2d 356, 368 (Mo App. W.D. 1992).

E. Should SERP payments be capitalized to plant accounts?

Findings of Fact

1. Public Counsel recommends an adjustment of $461,279 from plant-in-service to remove what it believes are capitalized SERP payments from the test year.[377]

2. Public Counsel argues that because SERP is accounted for on a pay-as-you-go accounting method and not an accrual method, it does not have any service cost component; and, it is inappropriate to capitalize any portion of SERP expense.[378]

3. Spire accounts for its SERP plan under Generally Accepted Accounting Principles (GAAP), Financial Accounting Standards (FAS 87) for financial reporting.[379]

4. FAS 87 allows for the capitalization of the service cost component of FAS 87 SERP expense.[380]

5. A service cost is the amount of cost that is booked in the current rate period for obligations that will be paid in future periods.[381]

6. Spire capitalizes its accrued SERP costs in accordance with the Uniform System of Accounts (USOA) and in accordance FAS 87. No payments are being capitalized.[382]

Conclusions of Law

A. Investor-owned natural gas utilities under this Commission's jurisdiction are obligated to use the Uniform System of Accounts (USOA) prescribed by the Federal Energy Regulatory Commission (FERC).[383]

[377] Ex. 410, Hyneman Rebuttal, p. 28; and *Initial Brief of the Office of the Public Counsel* (filed January 9, 2018), p. 41.
[378] Ex 403, Hyneman Direct, p. 16.
[379] Tr. 2211.
[380] Tr. 2211-2212.
[381] Tr. 2213.
[382] Ex. 21, Buck Surrebuttal, p. 18.

B. This Commission has authorized the use of FAS 87 for Laclede Gas Company and MGE and the recording of costs associated with company sponsored employee pension plans for ratemaking purposes.[384] FAS 87 allows for the capitalization of the service cost component of FAS 87 SERP expense.[385]

Decision

All the parties agree that SERP payments should not be capitalized. Further, Spire Missouri is not capitalizing *payments* made to employees under its SERP. However, Spire Missouri is capitalizing some SERP expense. Spire Missouri must recognize, as SERP expense for accounting purposes, a portion of those future SERP payments for each year of the current employee's expected service. This is the "accrued service cost" relating to SERP expense. Accrued service cost for SERP expense is appropriately capitalized under current FAS. The Commission determines that the adjustment requested by Public Counsel is not appropriate.

F. Should the prepaid pension asset be funded through the weighted cost of capital or long-term debt?

Findings of Fact

1. Public Counsel argues that a prepaid pension asset is similar to a long-term debt obligation and should not be considered to be funded by equity from

[383] 4 CSR 240-40.040.
[384] *Report and Order,* File Nos. GR-94-220 (issued August 22, 1994) and *Report and* Order, File No. GR-98-140 (issued August 21, 1998).
[385] Tr. 2211-2212.

shareholders. Because of this, Public Counsel argues that the pension asset should be funded at the cost of Spire Missouri's long-term debt.[386]

2. The prepaid pension asset represents a sum that investors have advanced that has not yet been paid by customers.[387]

3. Cash is fungible and attempting to earmark a funding source to specific assets within the same organizational structure is nothing more than optics - ultimately, all long-term financing (both debt and equity) will be used to fund all long-term assets, pensions or otherwise.[388]

4. Since 2002, through at least the last five rate cases for LAC, the prepaid pension asset has been included in rate base at the normal weighted average cost of capital.[389]

5. Staff accounted for the prepaid pension asset with a weighted cost of capital in its accounting schedules.[390]

Conclusions of Law

The Commission makes no additional conclusions of law on this issue.

Decision

The prepaid pension asset represents a sum that investors have advanced that has not yet been paid by customers. Cash is fungible and it is not easy or appropriate to pull one type of long-term asset out and assign it a particular funding source. The Commission determines that like other assets, the prepaid pension asset is

---

[386] Ex. 408, Pitts Direct, p. 6.
[387] Tr. 2074.
[388] Ex. 20, Buck Rebuttal, p. 13.
[389] Ex. 20, Buck Rebuttal, Schedule GWB-R2.
[390] Ex. 296, True-Up Hearing Accounting Schedules – LAC; and Ex. 297, True-Up Hearing Accounting Schedules – MGE.

appropriately included in rate base and is properly funded at the normal weighted average cost of capital.

XIII. Income Taxes

In addition to the accumulated deferred income tax presented by the parties at the hearing, the Commission has additionally considered the effects of the Tax Cuts and Jobs Act (TCJA).[391]

A. What is the appropriate amount of accumulated deferred income tax to include for LAC and MGE?

Findings of Fact

1. Deferred income taxes arise from temporary differences between the book and tax treatment of an item of income or expense. Thus, the deferred tax reserve is a net prepayment of income taxes by each company's customers prior to the time actual payment to the taxing authority is made.[392]

2. Under well-established regulatory principles, deferred taxes are treated as a reduction to rate base so ratepayers do not pay a return on funds provided to the utility at no cost.[393]

3. Staff and Spire Missouri have agreed that the statutory income tax rate of 38.3886 percent is the appropriate rate to apply in determining accumulated deferred income tax (ADIT) prior to the TCJA. They also indicated that their differences in determining the amount of ADIT would be resolved with the Commission's Report and

[391] Public Law No.: 115-97.
[392] Ex. 205, Staff Report - Cost of Service, p. 72; and Ex. 425, Hyneman Surrebuttal, pp. 23-24.
[393] Ex. 205, Staff Report - Cost of Service, p. 72.

Order.[394]

4. Public Counsel argued that the Commission should include $54.3 million of "FIN 48 liability" in ADIT.[395]

5. FIN 48 liability stems from uncertain tax positions in open tax years. Open tax years are years in which the Internal Revenue Service (IRS) may still audit the company's tax filings and could potentially rule against the company's position causing it to owe more taxes. Generally Accepted Accounting Principles (GAAP) allows the company to record only the portion of the tax liability on which the company expects to prevail as a deferred tax. The FIN 48 liability is the remaining portion that the company expects to have to pay. If the FIN 48 liability were included in ADIT, it would have the effect of decreasing revenue requirement by $5 million.[396]

<u>Conclusions of Law</u>

A. The Commission has previously decided against including FIN 48 liability in ADIT, determining that both ratepayers and shareholders benefit when a company takes uncertain tax positions with the IRS, because paying less income tax benefits the shareholders with increased revenues and the ratepayers with reduced tax expense.[397] The Commission found in that case that the best way to encourage the company to pursue uncertain tax positions was to treat the company fairly in the regulatory process by excluding from ADIT the FIN 48 liability, which the company expects to have to pay.

[394] *Staff's Notice*, (filed January 30, 2018), p. 1.
[395] Tr. 1082 and 1088.
[396] Tr. 1081-1083.
[397] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase Its Annual Revenues for Electric Service*, Case No, ER-2008-0318, Report and Order (issued January 27, 2009), p. 54.

Decision

Staff and Spire Missouri agree that the $54.3 million of FIN 48 liability should be excluded from ADIT. Public Counsel argues that it should be included. As previously found by the Commission, both ratepayers and shareholders benefit when the company takes an uncertain tax position with the IRS, because saving money on taxes benefits the company's bottom line and it also reduces the amount of tax expense for the ratepayers. As in File No. ER-2008-0318, the Commission determines that the best way to encourage the company to pursue these tax savings, and thus ultimately benefit both shareholders and ratepayers, is to exclude the FIN 48 liability from ADIT. The Commission finds the FIN 48 liability shall be excluded from consideration in the deferred taxes account.

B. What specific adjustments would be needed to include in rates any change in cost of service as a result of the Tax Cuts and Jobs Act for each of Spire's operating units?

Findings of Fact

1. The Tax Cuts and Jobs Act (TCJA) was signed into law on December 22, 2017, and will greatly reduce the amount of income taxes paid by Spire Missouri.

2. There has been no similar tax reform since 1986, and nothing similar is likely to happen again in the near future.

3. Beginning January 1, 2018, the TCJA will cause a significant (millions of dollars) reduction in income tax expense for Spire Missouri by reducing the federal corporate income tax applicable to Spire Missouri from 35 percent to 21 percent with

the effective composite federal and Missouri state tax rate being reduced from 38.3886 percent to 25.4483 percent. [398]

4. A reduction in Spire Missouri's federal corporate tax expense in revenue requirement due to the effects of the TCJA would reduce rates and save ratepayers millions of dollars annually.[399]

5. The effects of the reduced federal corporate tax expense can be calculated with great accuracy.[400]

6. The current accumulated deferred income tax reserve was deferred at a 35 percent corporate tax rate, but because of the reduction of the corporate tax rate by the TCJA, the reserve is overstated and will need to be flowed back to ratepayers.[401]

7. Spire Missouri is unique among large investor-owned utilities in Missouri in that it was before the Commission in the late stages of a rate proceeding when the TCJA became law and took effect. No other investor-owned utility in the state has the ability to reflect the tax changes in rates so quickly.

8. Spire Missouri has generally filed a rate case every four years.[402]

9. Not all of the effects of the TCJA are known as the Internal Revenue Service (IRS) and the Securities and Exchange Commission (SEC) have not yet issued guidance or promulgated rules on the implementation of the TCJA.[403]

[398] Tr. 2893 and 2895; and Ex. 754, Spire Tax Reform Quantification.
[399] Tr. 2881 and 2889.
[400] Tr. 2895.
[401] Tr. 2893-2894.
[402] Ex. 254, Majors Surrebuttal, p. 3.
[403] Tr. 2894.

10. The test year is a historic period in which revenues, expenses, and investment is measured, to serve as a foundational guide to set rates for a utility going forward.[404]

11. The test year in this case was set as the 12 months ending December 31, 2016, updated through June 30, 2017, and trued-up through September 30, 2017.[405]

12. The "matching principle" in the context of setting rates is the concept that a utility's revenues, expenses, rate base, and cost of capital are matched to each other during a generally consistent period such as the test year.[406]

13. If all the effects of the TCJA, including reduced income tax expense, are deferred under a regulatory liability until Spire Missouri's next rate case, the balance in that account will likely reach over $100 million, an unusually large regulatory liability.[407] This means that ratepayers would have been overpaying income tax expenses until the next rate case and would not start receiving the benefits of the income tax reduction set out in the TCJA for possibly as long as four years.[408] This is not a just and reasonable result.

14. Staff's recommendation on this issue is that the financial benefits of the TCJA should be returned to the ratepayers in this rate proceeding and any effects that are not able to be put into rates immediately should be tracked so they may be flowed back to the ratepayers or the utility in a later proceeding.[409]

---

[404] Tr. 2909.
[405] Ex. 205, Staff Report - Cost of Service, p. 4.
[406] Tr. 2909.
[407] Tr. 2974.
[408] Tr. 2973.
[409] Tr. 2894-2895.

15. Staff's witness Lisa Ferguson's method of estimating the change in the ADIT was clear and concise.[410] Ms. Ferguson based her calculation on the difference between the former composite tax rate of 38.3886 percent and the new effective composite tax rate of 25.4483 percent to determine the reduction to ADIT.[411] Ms. Ferguson also explained that she applied a 50/50 split between the "protected" and "unprotected" ADIT applying a 20-year amortization to protected ADIT and a 10-year amortization to unprotected ADIT.[412]

16. The amount of reduction to ADIT can be reasonably estimated as done by Staff's witness Ms. Ferguson. That estimate of the reduction to ADIT was $11.5 million (a $10.7 million reduction for LAC and an $815,000 reduction for MGE).[413]

17. MIEC witness Greg Meyer also reached a similar estimate for the income tax expense and ADIT reductions and used nearly identical methodology. [414]

18. Actual property tax expense paid in 2017 is also now known and measurable even though it falls outside the test year. That amount is an approximate $1.4 million increase.[415]

19. Property tax for 2018 is expected to increase but is not yet known and measurable because taxing authorities have not yet set the tax rates or set the assessed values and those taxes will not be assessed until later in 2018.[416]

Conclusions of Law

A. On December 22, 2017, the President of the United States signed into

[410] Tr. 2969-2970.
[411] Tr. 2968-2969.
[412] Tr. p. 2969-2972
[413] Tr. 2968-2970.
[414] Tr. 2993-2996; and Ex. 754, Spire Tax Reform Quantification.
[415] Tr. 2956
[416] Tr. p. 2935 and 2956.

law the Tax Cuts and Jobs Act[417] which amends the Internal Revenue Code of 1986. Specifically, sections of the Internal Revenue Code are amended dealing with the income tax rate that Spire Missouri will be required to pay on its revenues earned beginning January 1, 2018.

B. In setting just and reasonable rates, the Commission considers *all* relevant factors.[418]

Decision

The TCJA is the first major tax reform in the United States since 1986. As such, it will have a material effect on investor-owned public utilities and their ratepayers, including Spire Missouri, which is currently before this Commission for a rate case. A rate case is the only opportunity for the Commission to consider *all* factors surrounding the determination of just and reasonable rates that will allow the company an opportunity for a reasonable return on its investment. Because of this, the Commission cannot ignore the consequences of this extraordinary event.

Because of this major change in one of the factors the Commission considers in setting just and reasonable rates, the Commission requested information from the parties regarding the best and most fair way to incorporate the effects of the TCJA into the rates of Spire Missouri. By incorporating the TCJA in these rates, ratepayers will begin to see benefits of the TCJA almost immediately rather than waiting another three to four years until Spire Missouri files its next rate case. Additionally, by addressing these tax implications now, the potential for Spire Missouri to over-earn is also lessened. Addressing the TCJA implications in the current rate case is complicated by

[417] Public Law No.: 115-97.
[418] Subsection 393.270.4, RSMo; and *State ex rel. Util. Consumers' Council of Missouri, Inc. v. Pub. Serv. Comm'n*, 585 S.W.2d 41, 56 (Mo. banc 1979).

the past test year method of determining just and reasonable rates and by the late stage of the rate case process at which the law was passed. The Commission, however, finds it is necessary to address the TCJA in the current case in order to set just and reasonable rates.

At the hearing on this particular issue, the evidence was clear that effective January 1, 2018, Spire Missouri's basic federal corporate income tax rate will be reduced from 35 percent to 21 percent, with the effective composite federal and Missouri state tax rate being reduced from 38.3886 percent to 25.4483 percent.[419] Beginning January 1, 2018, this change will reduce income tax expense, which in turn if considered in rates, will reduce Spire Missouri's revenue requirement by millions of dollars and, therefore, would save ratepayers millions of dollars. While the specific income tax expense reduction cannot be calculated until the other decisions from this Report and Order are incorporated, it is a known and measurable expense. The new federal corporate tax rate is set and can easily be included in the revenue requirement calculation once the Commission has made a final decision in this case. Staff and MIEC calculated a very similar number in determining what the tax reduction might be if the Commission decided certain issues in a particular way. There is no reason why, using this same methodology with the actual decisions of the Commission incorporated, the reduction in income tax expense cannot be calculated making this a known and measurable expense.

Therefore, the Commission finds that based on the extraordinary event of the passage of the TCJA happening at the latter stages of this rate case, it is just and reasonable to reduce income tax expense in this case using the TCJA effective

[419] Ex. 754, Spire Tax Reform Quantification.

composite income tax rate of 25.4483 percent. Because these rates will not go into effect until near the end of March 2018, Spire Missouri's shareholders will receive the benefits of the lag and will maintain any previously collected taxes for the first quarter of 2018 with ratepayers seeing the benefits of reduced rates upon the effective date of the compliance tariffs.

The Commission further recognizes that not all of the effects of the TCJA are known at this time. The IRS has yet to promulgate rules or issue guidance on all the aspects of the TCJA. Therefore, the Commission will order that a tracker be established to account for any other effects (either over- or under-collection in rates) of the TCJA not captured by the current reduction in income tax expense for possible inclusion in rates at Spire Missouri's next rate case.

One additional consequence of the TCJA is its effect on ADIT. The parties presented evidence regarding the estimated effects, but because of the complex nature of deferred income taxes and the potential effect on cash flows to the company if the flow back of excess ADIT is not done correctly, this calculation as presented to the Commission still remains an estimate. The estimates of the percentage of "protected" versus "unprotected" ADIT and the lack of evidence surrounding the appropriate amortization periods for each category, convinces the Commission that effects of the TCJA on ADIT are not sufficiently know and measurable to include in the current rate case with any certainty beyond an estimate.

However, Spire Missouri and Staff indicated that they will be able to determine, based on the former composite tax rate of 38.3886 percent and the new effective composite tax rate of 25.4483 percent, an appropriate estimated amount to set as a reduction to ADIT.[420] That amount calculated by Staff's witness Lisa Ferguson is $11.5 million (a $10.7 million reduction for LAC and as $815,000 reduction for MGE). As part of its calculation, Staff applied a 50/50 split between the "protected" and "unprotected" ADIT applying a 20-year amortization to protected ADIT and a 10-year amortization to unprotected ADIT.

The Commission orders that the ADIT amount for purposes of rates in this case shall be reduced by $11.5 million. Additionally, the Commission orders that a tracker be established to defer any amounts in excess ADIT over or under the $11.5 million amount refunded in rates, from the effective date of rates resulting from this case, forward, for possible inclusion in a later rate case. Further, the determination of the actual split between protected and unprotected ADIT and the appropriate amortization periods will be determined in Spire Missouri's next rate case.

Finally, one of Spire Missouri's arguments against including the effects of the TCJA in the present case was that it was unfair to the company to not also include certain property taxes that also fall outside of the test year. Having considered these arguments the Commission agrees that actual property tax expense paid in 2017 is now known and measurable even though it falls outside the test year. And, coupled with the extraordinary event of decreased income tax expense it would not be just to exclude these know and measurable taxes (approximately $1.4 million) from increasing property tax expense. Therefore, as an offset to the reduction in current income tax expense, the Commission will include the 2017 property taxes as an expense for the new rates. However, as 2018 property taxes are still not known and measurable, the Commission will also establish a tracker to account for any amounts of property tax expense over or

[420] *Staff's Notice* (filed January 30, 2018).

under the amounts set out in rates for possible inclusion in Spire Missouri's next rate proceeding.

XIV. Incentive Compensation for Employees

The Commission presents the issues related to incentive compensation in a different order than set out in the parties' issues list.

A. Earnings Based Incentive Compensation – Should LAC and MGE be permitted to include earnings based and/or equity based employee incentive compensation amounts in base rates?

Findings of Fact

1. Earnings based incentives are usually incentives based on financial metrics such as, net income, return on equity, and increases in stock prices. These components of an incentive compensation plan focus utility management on maximizing net income. They also provide motivation to utility management to request rate increases that are higher than needed to earn a reasonable return.[421]

2. Earnings based incentive compensation primarily benefits shareholders.[422]

3. All employees of LAC and MGE are eligible for annual bonuses under Spire Missouri's Annual Incentive Plans (AIP).[423] This incentive compensation plan provides an annual cash payout to eligible union and nonunion participants based on four components, each component with its own objectives: corporate performance, business unit performance, individual performance, and team unit performance.[424]

[421] Ex. 403, Hyneman Direct, p. 21 and Ex. 263, Young Surrebuttal, p. 26.
[422] Tr. 2721; Ex. 403, Hyneman Direct, p. 19; and Ex. 263, Young Surrebuttal, p. 25.
[423] Ex. 205, Staff Report - Cost of Service, p. 101; and Ex. 48, Mispagel Rebuttal, p. 6.
[424] Ex. 205, Staff Report - Cost of Service, pp. 101-102.

4. Under the AIP, corporate performance and business unit performance are measured with financial metrics and net economic earnings per share (NEEPS) and operating income, respectively. Payouts under these two components are applicable to all employees.[425]

5. Corporate based earnings provide an incentive for management to focus on the non-Missouri regulated portions of the overall corporate structure which could be detrimental due to reduced focus on Missouri ratepayers.[426]

6. The Commission has previously determined that compensation based on corporate earnings is focused on shareholder wealth maximization and should be assigned to the shareholders.[427]

7. The Commission has a long history of removing earnings based employee compensation from rates. Examples of cases in which the Commission decided against allowing incentive compensation tied to financial benchmarks include: EC-87-114, Union Electric; TC-89-14, Southwestern Bell; TC-93-224, Southwestern Bell; GR-96-285, Missouri Gas Energy; GR-2004-0209, Missouri Gas Energy; ER-2006-0314, Kansas City Power & Light; and ER-2007-0291, Kansas City Power & Light.[428]

8. An incentive to maximize earnings could compromise service to ratepayers by reducing costs that are related to the quality of service. Corporate based earnings incentives provide an incentive for management to focus on the non-Missouri regulated portions of the overall corporate structure (including non-regulated business

[425] Ex. 205, Staff Report - Cost of Service, p. 102.
[426] Ex. 263, Young Surrebuttal, p. 25.
[427] *In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Service Area*, File No. GR-96-285.
[428] Ex. 263, Young Surrebuttal, pp. 24-25.

segments and out-of-state utilities), which could be detrimental to Missouri-regulated ratepayers.[429]

9. Spire Missouri admits that earnings based incentive compensation, in the form of stock, is meant to align the interests of its directors, officers, and employees with the interests of the shareholders.[430]

10. Any metric based on earnings per share is also based on the performance of all of Spire Inc.'s subsidiaries and non-Missouri regulated activities, because Spire Inc. is the only entity that has shares outstanding.431

11. Individual goals of certain executives were based on Spire Inc.'s achievement of earnings per share and for meeting Spire Inc.'s growth objectives.432 A number of the metrics set out were also tied to the performance of Spire's Alabama and Mississippi operations.433

12. Spire Missouri's incentive based compensation for directors and executives is based entirely on financial metrics.[434] For other Spire Missouri employees, 50 percent of incentive compensation is attributed to financial metrics and 50 percent is attributed to other metrics assigned to that employee.[435] Public Counsel does not support the inclusion of incentive compensation payments based on earning metrics such as net income, earnings per share, or stock appreciation. Public Counsel also

[429] Ex. 263, Young Surrebuttal, p. 25.
[430] Ex. 403 Hyneman Direct, p. 23.
[431] Ex. 205, Staff Report - Cost of Service, pp. 17-18.
[432] Ex. 263, Young Surrebuttal, p. 30, citing Ex. 48, Mispagel Rebuttal, p. 8.
[433] Ex. 205, Staff Report - Cost of Service, p. 103.
[434] Tr. 2696.
[435] Tr. 2692 and 2697.

does not support the inclusion of any short-term compensation based on incentives that do not directly benefit utility customers.[436]

13. The third component of the AIP, individual performance, is applicable only to nonunion employees. The fourth component, team unit performance, is applicable only to union employees.[437] These components of the AIP are addressed elsewhere in this order.

Conclusions of Law

A. Traditionally, the Commission has not allowed the recovery of incentive compensation tied to financial metrics in rates because "[t]hose financial incentives seek to reward the company's employees for making their best efforts to improve the company's bottom line. Improvements to the company's bottom line chiefly benefit the company's shareholders, not its ratepayers. Indeed some actions that might benefit a company's bottom line, such as a large rate increase, or the elimination of customer service personnel, might have an adverse effect on ratepayers."[438]

B. The Commission's historical decisions are represented in its *Report and Order* in KCPL's rate case in File No. ER-2007-0291. Beginning on page 49 of that *Report and Order* the Commission said:

> KCPL has the right to tie compensation to [earnings per share]. However, because maximizing [earnings per share] could compromise service to ratepayers, such as by reducing maintenance, the ratepayers should not have to bear that expense. What is more, because KCPL is owned by Great Plains Energy, Inc., and because GPE has an unregulated asset,

[436] Ex. 403, Hyneman Direct, p. 22.
[437] Ex. 205, Staff Report - Cost of Service, p. 103.
[438] *In the Matter of Missouri Gas Energy's Tariffs to Implement a General Rate Increase for Natural Gas Service,* Case No. GR-2004-0209, Report and Order (issued September 21, 2004), p. 43. See also similar conclusions in *In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to implement Its Regulatory Plan*, Case No. ER-2007-0291, Report and Order (issued December 6, 2007), p. 49 (the Commission denied Kansas City Power & Light's request to recover compensation tied to earnings per share).

> Strategic Energy L.L.C., KCPL could achieve a high [earnings per share] by ignoring its Missouri ratepayers in favor of devoting its resources to Strategic Energy. Even KCPL admits it is hard to prove a relationship between earnings per share and customer benefits. Nevertheless, if the method KCPL chooses to compensate employees shows no tangible benefit to Missouri ratepayers, then those costs should be borne by shareholders, and not included in cost of service. [footnotes omitted]

C. Subsection 393.150.2, RSMo, provides that Spire Missouri has "the burden of proof to show that the…proposed increased rate is just and reasonable…"

Decision

The Commission has traditionally not allowed earnings based or equity based compensation to be recovered in rates because such incentives are primarily for the benefit of shareholders and not for the benefit of the ratepayers. As the Commission has said in the past, incentivizing employees to improve the company's bottom line aligns the employee interests with the shareholders and not with the ratepayers. Aligning interests in this way can negatively affect ratepayers. The evidence in this case shows that Spire Missouri's nonunion employees' incentive compensation plan is made up of 50 percent financial metrics. Additionally, the executive and director incentive compensation is 100 percent based on financial metrics.

The Commission finds that Spire Missouri's earning based and equity based incentive compensation is primarily for the benefit of the shareholders and not for the benefit of the ratepayers. Therefore, the Commission determines that Spire Missouri has not met its burden of proving that its proposed increase in rates for earnings based and equity based incentive compensation plans is just and reasonable. Spire Missouri shall not recover earnings based or equity based employee incentive compensation amounts in rates.

B. What criteria should be applied to determine appropriate levels of employee incentive compensation?

Findings of Fact

1. As stated above, for nonunion, nonexecutive Spire Missouri employees, 50 percent of incentive compensation is attributed to financial metrics, but 50 percent is attributed to individual performance metrics assigned to that employee.[439]

2. Spire Missouri's individual performance component of its incentive compensation plan is not based on financial metrics, but rather is based on service and operational metrics.[440]

3. An incentive compensation plan can motivate performance of employees to the benefit of ratepayers.[441]

4. An incentive compensation plan can also be a recruitment and retention tool allowing Spire Missouri to retain and motivate talented employees, which is also of benefit to the ratepayers.[442]

5. Most publicly-traded companies the size of Spire Missouri offer an incentive compensation plan.[443]

6. Staff used five standards that had been previously articulated by the Commission to evaluate the nonunion employee incentive compensation component of Spire's AIP. Those standards were: 1) does the goal provide the employee an incentive to perform at a level above what is already required for the applicable job; 2) does a goal require improvement over past performance; 3) is the goal objective and

[439] Tr. 2692 and 2697.
[440] Ex. 48, Mispagel Rebuttal, p. 7.
[441] Ex. 48, Mispagel Rebuttal, p. 5.
[442] Ex. 48, Mispagel Rebuttal, pp. 5 and 7.
[443] Ex. 48, Mispagel Rebuttal, p. 5.

measurable; 4) was the goal related to Missouri regulated operations; and 5) was the goal, if achieved, directly linked to overall ratepayer benefit.[444]

7. For the union employees, the incentive compensation plan establishes team goals. A majority of those team goals are customer-oriented, such as average call handle time, call abandonment rate, leak response time, etc.[445]

Conclusions of Law

The Commission makes no additional conclusions of law on this issue.

Decision

Staff used the five standards previously articulated by the Commission for evaluating the nonunion employee individual performance metrics for incentive compensation. The Commission has previously used these criteria in determining whether to allow incentive based compensation and finds that those criteria are generally appropriate to evaluate employee incentive compensation plans. However, in this case, the Commission was not persuaded by Staff's evaluations of the specific individual performance metrics that the non-earnings and non-equity based portion of the incentive compensation plan was inadequate to encourage and motivate employees to the benefit of the ratepayers. Therefore, the Commission finds that the individual performance component (50 percent of the nonunion, nonexecutive and director incentive compensation) of Spire Missouri's employee incentive compensation plan encourages, motivates, and retains talented employees to the benefit of ratepayers and should be included in revenue requirement.

---

[444] Ex. 205, Staff Report - Cost of Service, p. 27; and Ex. 263, Young Surrebuttal, p. 27.
[445] Ex. 205, Staff Report - Cost of Service, p. 103.

C. What is the appropriate amount of employee incentive compensation to include in base rates?

Findings of Fact

1. Spire Missouri's overall incentive compensation package for nonunion employees is heavily weighted toward financial metrics, and contains individual metrics that are vague, not designed to incent an employee to perform at a level higher than what is required for their base salary, and are not linked to ratepayer benefit.[446]

2. There is no opposition to including incentive compensation for union employees as this is the result of a collective bargaining agreement.[447]

3. The Staff recommended a total reduction to Spire Missouri's revenue requirement of $4.8 million for non-union employee incentive compensation.[448]

4. The Commission has determined in this Report & Order that Spire Missouri's incentive compensation program expense should be disallowed.

Conclusions of Law

The Commission makes no additional conclusions of law on this issue.

Decision

The Commission has determined that 50 percent (the earnings based and equity based portions) of Spire Missouri's nonunion, non-executive or director employee incentive compensation plans should be disallowed from rates. Further, the executive and director incentive compensation plan, which is 100 percent earnings and equity based, shall also be disallowed. Incentive compensation for union employees, however, is appropriately included in rates because this is the result of collectively

[446] Ex. 263, Young Surrebuttal.
[447] Staff Initial Brief, p. 78; Public Counsel Initial Brief, p. 51;
[448] Ex. 268, Reconciliation – LAC; and Ex. 269, Reconciliation – MGE.

bargaining agreements. Therefore, Spire Missouri's proposed revenue requirement shall be reduced by 100 percent of the executive and director's incentive compensation plan and 50 percent of the other nonunion employee incentive compensation plan.

D. Should LAC and MGE be permitted to capitalize earnings based and equity based employee incentive compensation amounts in base rates?

Findings of Fact

1. The Commission previously determined that earnings based and equity based incentive compensation should not be recovered in rates.

2. Utilities typically capitalize a portion of their incentive compensation costs.[449]

3. Staff proposes to adjust base rates by removing the present value of the capitalized incentive compensation amounts from 2003 to present that it contends was inappropriately capitalized following past settled rate cases where the subject of incentive compensation was not litigated.[450]

4. Every LAC rate case since 2003 has been resolved through settlement and neither the issue of incentive compensation nor the issue of incentive compensation capitalization were specifically addressed in any stipulation or litigation.[451]

Conclusions of Law

No additional conclusions of law are necessary for this issue.

---

[449] Tr. 2731.
[450] Ex. 205, Staff Report - Cost of Service, p. 104.
[451] Ex. 263, Young Surrebuttal, p. 23; and Tr. 2731-2731.

Decision

The Commission has decided above that earnings based and equity based incentive compensation should not be recovered in rates. Thus, that incentive compensation expense will not be included in rates and no part of the earnings based or incentive based compensation for the current case (back to the previous settlement) should be capitalized in rate base. However, Staff has also proposed to remove from rate base the present value of incentive compensation that it contends was inappropriately capitalized by Spire Missouri following past settled rate cases where the subject of incentive compensation was not litigated. The Commission finds that it is not appropriate to make this adjustment. Because the stipulation and agreement settled all issues but did not specifically address the capitalization of incentive compensation, the Commission will not now reach back to that settled case and remove capital from rate base. The Commission determines that no adjustment shall be made to remove the present value of any capitalized past incentive compensation.

E. To the extent the Commission declines to include employee incentive compensation in rates, what adjustment should be made to base salaries paid to employees?

Findings of Fact

1. "[T]he company uses industry market data from surveys and other publicly available sources to help determine competitive compensation, both on the base and incentive level."[452]

2. Both Staff and Spire Missouri compare base salary to market base

[452] Ex. 48, Mispagel Rebuttal, p. 6.

salary.[453]

3. Spire Missouri also compares its incentive compensation to market based incentive compensation.[454]

4. LAC's and MGE's actual payout for individual incentive compensation was approximately 13 percent above market compensation.[455]

Conclusions of Law

The Commission makes no additional conclusions of law on this issue.

Decision

Both Staff and Spire Missouri compare the base salary paid by Spire Missouri to market salaries. Then Spire Missouri also compares incentive compensation to market incentive compensation. Thus, base salary is not less than market base salary and there is no need for any upward adjustment. Spire Missouri is free to compensate its employees in the manner it sees fit. However, in order to include the earnings based and equity based incentive compensation into rates, Spire Missouri must show that it is just and reasonable for the ratepayers to pay. The Commission determines Spire Missouri has not met its burden to show that any upward adjustment to base salaries is just and reasonable to include in rates. Therefore, no adjustment in compensation expense shall be made due to the Commission disallowing portions of Spire Missouri's incentive compensation plans expense.

[453] Tr. 2720.
[454] Tr. 2720.
[455] Ex. 263, Young Surrebuttal, p. 28.

XV. Uncollectibles

What is the appropriate amount of bad debt to include in base rates?

Findings of Fact

1. In Spire Missouri's Fiscal Year 2016, the company made a significant change to its write-off policy for both LAC and MGE. LAC went from writing off bad debt (considering it uncollectible) in 180 days after disconnection to writing off bad debt in 360 days after disconnection. MGE went from writing off bad debt in 30-45 days after disconnection to writing off bad debt in 360 days after disconnection. This change makes it difficult to compare the net uncollectible levels in 2016 (the test year) and those experienced prior to 2016.[456]

2. Because of this difficulty, Staff calculated its bad debt expense level based on an "annualized/normalized level" of actual bad debt for the most current twelve-months (the twelve months ending June 30, 2017).[457]

3. Public Counsel recommended that bad debt expense be set at the level of the test year uncollectibles.[458]

4. Spire Missouri calculated bad debt expense based on both a three-year average and on a five-year average and normalized the data due to the change in write-off policy.[459]

5. To normalize the bad debt expense for the change in write-off policy, Spire Missouri's witness, Timothy Krick, generated a list of all customer balances that had write-off dates scheduled on or after October 1, 2017, and then subtracted 180 days or

[456] Ex. 23, Krick Direct, pp. 3-5.
[457] Ex. 205, Staff Report - Cost of Service, p. 136; and Ex. 253, McMellen Surrebuttal, pp. 2-3.
[458] Ex. 403, Hyneman Direct, p. 41.
[459] Ex. 24, Krick Rebuttal, pp. 9-10.

330 days for customers of LAC and MGE, respectively, to estimate when the customers would have systematically been written-off under the old policy.[460]

6. The Commission finds that Spire Missouri's normalization gives an accurate estimate of future bad debt expense.

7. Fiscal years 2016 and 2017 were two of the warmest years on record for LAC and MGE. Thus, write-offs for that time period would artificially be lower than other years.[461]

8. A twelve-month period is not long enough to fairly represent bad debt write-off trends and to fairly project future expense. An average over at least three years normalizes unusual variances that can occur in a shorter period such as twelve months.[462]

9. A five-year average is an even better predictor of future write-offs. A five-year average includes more data points, which reduces the standard deviation in statistical terms. Adding more data points helps to average out unusually warm and cold winters.[463]

10. The five-year average bad debt for LAC is $8.3 million, and the five-year average bad debt for MGE is $4.5 million.[464]

Conclusions of Law

The Commission makes no additional conclusions of law on this issue.

[460] Ex. 24, Krick Rebuttal, pp. 9-10, Schedule TWK-R1.
[461] Tr. 975.
[462] Ex. 24, Krick Rebuttal, p. 8.
[463] Ex. 24, Krick Rebuttal, p. 9; and Tr. 966 and 976.
[464] Tr. 966; and Ex. 24, Krick Rebuttal, Schedule TWK-R1.

Decision

Both LAC and MGE had a change in write-off policy that makes comparing the data in the test year difficult. However, looking at only a twelve-month period of bad debt expenses does not provide enough data to project trends in bad debt expense. The five-year normalized average calculated by Spire Missouri, on the other hand, has sufficient data points to smooth out variations in bad debt. The Commission finds that a five-year average is the most appropriate method to calculate the amount of bad debt to include in rates. The Commission also finds that Spire Missouri's normalization calculation provided an accurate estimate of future bad debt expense. Thus, the Commission determines the appropriate amount of bad debt to include in rates are $8.3 million for LAC, and $4.5 million for MGE as calculated by Mr. Krick.

XVI. Performance Metrics

A. Should a proceeding be implemented to evaluate and potentially implement a performance metrics mechanism? If yes, how should this be designed?

Findings of Fact

1. Currently, neither LAC nor MGE have performance incentives based upon the achievement of any Commission-approved performance metrics. Spire Missouri proposes the Commission establish a separate proceeding[465] to consider incentivizing performance for Spire Missouri based on performance metrics in the areas of customer service, safety, and reliability, as well as other areas.[466] This performance incentive

[465] Ex. 8, Lobser Surrebuttal, p. 23.
[466] Ex. 6, Lobser Direct, p.41.

would be independent of the revenue requirement in a subsequent rate case.[467]

2. LAC already monitors a variety of service, safety, reliability, and other operational metrics. LAC has previously provided those metrics to Staff. Spire Missouri proposes using historic performance levels to establish an appropriate benchmark for future performance.[468]

3. Spire Missouri believes that performance metrics align the interests of the shareholders with the customers by holding the company financially accountable for how well it serves customers.[469]

4. In this rate case, Spire Missouri did not provide a specific program with specific performance metrics to be considered. At this point, Spire Missouri is proposing that the Commission form a working group to develop a program with the following guidelines:

a. the total sum of any positive or negative financial adjustments associated with exceeding or falling below such performance metrics not exceed $2 million annually, after tax, across both business units (LAC and MGE);

b. that each performance metric have a range of acceptable annual performance that is reasonably achievable based on historical experience;

c. Spire Missouri report quarterly on results, toward an annual result;

d. any financial adjustments for each particular metric be equivalent in value and only be made for performance that falls outside the range

[467] Ex. 6, Lobser Direct, p.42.
[468] Ex. 6, Lobser Direct, p.41.
[469] *Initial Post-Hearing Brief of Laclede Gas Company and Missouri Gas Energy* (filed January 9, 2018), p. 115-116.

established for he metric; and

e. any financial adjustments be credited each year to a regulatory asset or liability, as applicable, subject to an annual review to confirm their accuracy: and the accumulated net value of such financial adjustments be tracked for return to or recovery from customers over a four-year period in Spire Missouri's next rate case proceeding. [470]

5. Staff takes no formal position on whether a proceeding should be implemented to evaluate and potentially implement a performance metric mechanism.

6. Public Counsel opposes implementing a proceeding to investigate performance mechanisms, indicating a lack of specific proposed metrics on the record.[471] Public Counsel also opposes the formation of a working group that might merely be a platform for topics outside providing safe and reliable service at just and reasonable rates.[472]

Conclusions of Law

A. There is no statutory authorization or prohibition for the implementation of incentives related to performance metrics.

Decision

The Commission supports performance metrics and incentives but because none were proposed by Spire Missouri, it was not possible to build a record supporting such in this case. A separate docket after the case would not be helpful for setting metrics in this case because it would not be possible to use them to modify existing

[470] *Initial Post-Hearing Brief of Laclede Gas Company and Missouri Gas Energy* (filed January 9, 2018), pp. 116-117.
[471] Ex. 421, Marke Surrebuttal, p. 4.
[472] Ex. 421, Marke Surrebuttal, pp. 18-19.

rates. The commission hopes the record in the next rate case is more developed on this issue, allowing the commission to fully consider implementation of such mechanism. Therefore, the Commission will not establish a working group or separate proceeding to explore performance metrics for Spire Missouri at this time. Spire Missouri is encouraged to bring a more complete proposal in its next rate case.

XVII. Transition Costs

Should LAC's and MGE's cost of service be adjusted to reflect the recognition of merger synergies through the test year?

Findings of Fact

1. One reason public utilities merge with and acquire one another is to benefit shareholders.[473] Mergers and acquisitions cost money ("transition costs") but increase efficiency ("merger synergies").[474] Merger synergies also reduce expenditures ("synergy savings").[475]

2. Sound ratemaking practice does not encourage or discourage public utilities from merging when such merger is discretionary.[476] Rather, it maintains consistent ratemaking policy as to transition costs and synergy savings.[477] No special accounting or ratemaking treatment is necessary for a public utility to benefit from synergy savings.[478]

---

[473] Ex. 224, Oligschlaeger Rebuttal, p. 15-16.
[474] Ex. 224, Oligschlaeger Rebuttal, p. 15-16.
[475] Ex. 224, Oligschlaeger Rebuttal, p. 15-16.
[476] Ex. 224, Oligschlaeger Rebuttal, p. 15-16.
[477] Ex. 224, Oligschlaeger Rebuttal, p. 15-16.
[478] Ex. 224, Oligschlaeger Rebuttal, p. 15.

3. Merger synergies may also benefit customers. Quantifying that benefit is possible,[479] but it is subjective and extremely difficult, even for experts.[480]

4. Spire Missouri's predecessor Laclede Gas Company merged with Alagasco four years ago, and merged with EnergySouth one and one-half years ago, resulting in merger synergies.[481] Because Laclede Gas Company, now Spire Missouri, has not had any change to its applicable tariffs since those mergers, Spire Missouri has retained all synergy benefits due to regulatory lag, while customer bills reflected no such benefit.

Conclusions of Law

A. Because Spire Missouri seeks an increase in rates for merger synergies, Spire Missouri has the burden to prove that such an increase is just and reasonable.[482]

Decision

Public utilities are largely motivated to merge with and acquire one another for purposes of benefitting shareholders. Shareholders benefit from these mergers because the synergy savings mean decreased expenses and increased profits. While it is clear that such transactions can also present some incidental benefits for ratepayers, they are difficult to quantify. Rates for Spire Missouri have not changed since the mergers, so Spire Missouri shareholders and not ratepayers, through regulatory lag, have received the benefit of any synergy savings for four years since merging with Alagasco and one-and-one-half years since merging with EnergySouth. In this case, Spire Missouri presented insufficient credible evidence for the Commission to make a finding of the

[479] Ex. 55, *Stipulation and Agreement* in Case No. GM-2013-0254.
[480] Ex. 224, Oligschlaeger Rebuttal, p. 15.
[481] Ex. 9, Lobser Surrebuttal p. 15.
[482] Section 393.150.2, RSMo. The burden of proof does not shift. *Been v. Jolly*, 247 S.W.2d 840, 854 (Mo. 1952).

exact savings achieved or of an amount that would be just and reasonable to include in rates. Further, the Commission is not persuaded that it would be just and reasonable for Spire Missouri's rates to continue to include the benefits of synergy savings that it has enjoyed for the last several years. Because Spire Missouri has not met its burden of proof to show that increasing rates by an amount to include synergy savings on a going forward basis is just and reasonable, the Commission will not include synergy savings in rates.

XVIII. Low Income Energy Assistance Program

A. What is the appropriate funding level for each division?

Findings of Fact

1. On January 9, 2018, LAC and MGE, Staff, DE, and Consumers Council filed a Partial Stipulation and Agreement Regarding Low-Income Energy Affordability Program that has been approved in this order. The only issue left for the Commission to resolve for the Low-Income Energy Affordability Program is the level of funding.[483]

2. The current level of funding for LAC's low-income energy affordability program is $600,000 annually, which LAC requests to maintain.[484]

3. MGE does not currently have a low-income energy affordability program. MGE proposes to fund a new one at $500,000 annually.[485] However, LAC and MGE

[483] Partial Stipulation and Agreement Regarding Low-Income Energy Affordability Program (filed January 9, 2018), EFIS No. 512.
[484] Ex. 18, Weitzel Surrebuttal, p. 26.
[485] Ex. 17, Weitzel Rebuttal, p. 12.

are amenable to a moderately higher level of funding.[486]

4. "Energy burden" is defined as the percentage of total income spent by a family on their utility bills. On average, Missouri low-income families spend 14 percent of their income on utilities and 30 percent on housing cost, while middle income families spend on average four percent of their income on utilities. In the dense urban areas of the state, which are served by Spire Missouri, it is common to have families with energy burdens that exceed 30 percent of their income, not including other housing costs.[487]

5. Low-income energy needs exceed $5 million in each service area.[488]

6. The Low-Income Home Energy Assistance Program (LIHEAP) is the federal fuel assistance program designed to help pay low-income heating and cooling bills.[489]

7. Current LIHEAP funding is not adequate to meet the needs of low-income Missourians. The gross LIHEAP allocation to Missouri was $65.7 million in 2016 and the number of average annual low-income heating and cooling bills "covered" by LIHEAP was 101,018. In comparison, the gross LIHEAP allocation to Missouri in 2015 reached $73 million and covered 92,403 average annual bills and ran out of money before the end of the previous heating season.[490]

8. Consumers Council and DE proposed the programs be funded at $1 million each for LAC and MGE service territories.

9. Even though there is a great need for funding of low-income energy

[486] *Initial Post-Hearing Brief of Laclede Gas Company and Missouri Gas Energy* (filed January 9, 2018), p. 122; see also Tr. 696 (in which Spire Missouri's counsel stated Spire Missouri believes it needs to do all it can to help its most vulnerable customers maintain utility service).
[487] Ex. 800, Hutchinson Direct, p. 4.
[488] Ex. 800, Hutchinson Direct, pp. 5-6.
[489] Ex. 800, Hutchinson Direct, p. 5.
[490] Ex. 800, Hutchinson Direct, p. 5.

assistance programs, LAC's funds were not all distributed in years past.[491] Because of this, Staff and Public Counsel oppose increasing funding for the program.

10. The new program under the stipulation and agreement has been designed similar to a successful program, Ameren Missouri's Keeping Current. Additionally, the agreement provides that this program will be funded through a regulatory deferral so that any unused allocations will not be included in the revenue requirement.

Conclusions of Law

The Commission makes no additional conclusions of law on this issue.

Decision

The Commission finds that the energy burden low-income consumers face, combined with the LIHEAP funding decrease, requires a moderate increase of funding over what was proposed for LAC's and MGE's proposed low-income energy affordability programs. However, it is not reasonable to fund these programs at the full level of need because ultimately, ratepayers will be paying for these programs. The Commission determines that a 50 percent increase over the companies' proposals is a reasonable increase. Thus, the Commission orders these programs be funded at $900,000 for LAC and $750,000 for MGE.

[491] Ex. 501, Kohl Direct, pp. 7-8.

XIX. CHP

A. Should LAC and MGE implement a CHP pilot program as proposed by Division of Energy?

Findings of Fact

1. Combined heat and power (CHP) refers to technologies that simultaneously generate electricity and use thermal energy from a single fuel source. This is accomplished by recovering the otherwise wasted heat from the electric generation process and using it to provide the thermal load for a building. CHP results in a total system efficiency of approximately 75 percent, compared with separate heat and power at approximately 50 percent.[492]

2. Missouri has at least 21 CHP installations, including schools, colleges, universities, hospitals, hotels, government, agriculture, and chemical facilities.[493]

3. DE has an interest in promoting the utilization of CHP technology to improve energy reliability and resiliency for critical infrastructure, such as hospitals, nursing homes, public water and wastewater treatment facilities, government facilities, emergency shelters, and data centers.[494]

4. DE proposes that the Commission approve a CHP pilot program, whereby Spire Missouri would work with DE to encourage customers in Spire Missouri's service area to adopt CHP technology. DE recommends that the Commission establish the following guidelines for the CHP pilot program:

- Establish a definition of critical infrastructure that encompasses the range of CHP applications, from individual facilities (e.g., hospitals) to communities (e.g., hospital plus water and wastewater treatment facility, shelter, and grocery store).

[492] Ex. 502, Epperson Direct, p. 4; and Ex. 214, Eubanks Rebuttal, p. 2.
[493] Ex. 502, Epperson Direct, p. 5-6; and Tr. 861-862.
[494] Ex. 502, Epperson Direct, pp. 12-13.

- Authorize Spire Missouri to investigate and develop a proposed CHP pilot program to serve critical infrastructure, with a total program budget not to exceed $5.1 million for 10 projects and with each specific project proposed to be included in the program filed with the Commission for its approval within 60 days.
- Allow Spire Missouri to track, and in the future seek recovery of, the cost of participating in the pilot program. Such costs might include offsetting up to $10,000 of the cost of a project's feasibility study following a positive initial screening conducted by CHP TAP identifying a customer as a good candidate for CHP, the cost of any contribution by Spire Missouri to a project's installed cost (up to the lesser of $500,000 or 30 percent of a project's installed cost), and any buy-down on the rate of interest offered for financing of a project.
- Allow Spire Missouri to extend the cost recovery periods (up to 15 years) for customer repayments on the customer portion of the cost of natural gas line extensions and other natural gas facilities necessary to develop a CHP system.
- Allow Spire Missouri to offer on-bill financing to assist potential CHP customers in funding the necessary capital improvements needed for CHP installation.
- Spire Missouri should use a societal cost test to evaluate the potential benefits of critical infrastructure projects. Spire Missouri currently uses a societal cost test in evaluating custom rebates under its Commercial and Industrial Rebate Programs.
- For projects jointly offered with electric utilities offering Missouri Energy Efficiency Investment Act (MEEIA) programs, the Commission should direct that the costs and benefits of CHP be symmetrically valued by developing a transparent and reproducible formula to reasonably allocate and assign the value of energy savings and project costs between natural gas and electric companies and customers.
- Allow a potential CHP pilot program customer to participate in otherwise-applicable EDRs or Special Contract service rates.[495]

5. DE's proposal has the potential to affect the sales and revenues of electric utilities that are not participating as intervenors in this case.[496]

6. DE's proposal would allow Spire Missouri to recover costs associated with contributing to a project's installed cost, which may be a prohibited promotional practice.[497]

---

[495] Ex. 502, Epperson Direct, pp. 16-18.
[496] Ex. 214, Eubanks Rebuttal, p. 4.

7. MEEIA is a state statutory policy which is designed to encourage electric investor-owned utilities to offer and promote energy efficiency programs designed to reduce the amount of electricity used by the utility's customers. Under MEEIA and with Commission approval, electric utilities may offer demand-side programs and special incentives to participating customers. MEEIA does not apply to natural gas utilities, but DE's proposed pilot program would be jointly offered by Spire Missouri and the electric utilities.[498]

8. DE's proposal does not include any specific recommendations or formulas relating to MEEIA, and does not discuss whether individual CHP can qualify as demand-side programs under either the MEEIA statute or the Commission's rules.[499]

9. DE's CHP pilot program proposal is still in the conceptual phase and does not state a time period for the program or how it would be evaluated. The proposal lacks specificity regarding on-bill financing, line extension policies, and interaction with MEEIA.[500]

10. The $5.1 million recommended for DE's pilot program would equate to an additional 25 percent beyond Staff's total revenue requirement recommendation in direct testimony, subject to true-up.[501]

Conclusions of Law

The Commission makes no additional conclusions of law on this issue.

Decision

DE has proposed a pilot program with the stated goal of promoting CHP

---

[497] Ex. 214, Eubanks Rebuttal, p. 4-5.
[498] Ex. 214, Eubanks Rebuttal, p. 7.
[499] Ex. 214, Eubanks Rebuttal, p. 7.
[500] Ex. 214, Eubanks Rebuttal, p. 9.
[501] Ex. 244, Eubanks Surrebuttal, p. 3-4.

technology to improve energy reliability and resiliency for critical infrastructure. The Commission supports that goal, but DE has not been persuasive that the $5.1 million pilot program as proposed should be approved and paid for by ratepayers. The proposed pilot program lacks sufficient details, as it does not contain specific recommendations or formulas relating to MEEIA, does not state a time period for the program or how it would be evaluated, and lacks specificity regarding on-bill financing, line extension policies, and interaction with MEEIA. This lack of detail does not allow the Commission to determine if and to what extent the pilot program may affect the sales and revenues of electric utilities that are not participating as intervenors in this case, may be a prohibited promotional practice, and may be inconsistent with MEEIA requirements. For all these reasons, the Commission concludes that the CHP pilot program should not be approved as proposed by DE. The Commission encourages the parties to continue discussions on how best to improve energy reliability and resiliency for critical infrastructure and submit more detailed recommendations in the future.

XX. AMR Meters

A. What is the appropriate amount to include in rates to account for expenses related to LAC's purchase of automated meter reading (AMR) devices?

<u>Findings of Fact</u>

1. Prior to July 1, 2017, LAC leased AMR devices from the company Landis & Gyr, who both owned and maintained the AMR devices.[502] As part of the contract LAC was charged a meter read rate of $0.985 per meter, per month.[503]

---

[502] Ex. 65, Lobser True-Up Rebuttal, p. 1.
[503] Ex. 292, Ferguson True-Up Rebuttal, p. 2.

2. Effective July 1, 2017, LAC purchased the AMR devices from Landis & Gyr for $16.6 million[504] ($16,624,220 for the 700,262 already deployed meter interface units).[505]

3. By purchasing the AMR devices LAC reduced the price per meter read from $0.98 to $0.24, which directly benefits ratepayers.[506] Landis & Gyr still read the meters under contract with LAC at a rate of $0.24 per meter per month until June 30, 2020, and at $0.30 per meter per month after that date.[507]

4. Staff included in its calculated cost of service the $16,624,220 that LAC paid for the AMR devices.[508]

5. The AMR devices are distinct from the meters they monitor. Because of this, Staff recommends the establishment of Account No. 397.2 – AMR Devices.[509]

6. The useful life of the AMR devices is 20 years based on battery life. However, LAC will be switching to a new system in 2020 with replacement of all AMR devices completed by 2024. Thus, Staff recommends that the cost be *amortized* over a period of 7.5 years.[510]

7. Public Counsel agrees that the AMR should be listed in a new plant sub-account for the AMR meter interface units in Account 397.2 – AMR Devices. OPC recommends a five percent *depreciation* rate based on the average service life of the asset.[511]

8. Spire Missouri is also seeking to recover approximately $700,000 in rates

[504] Ex. 65, Lobser True-Up Rebuttal, p. 2.
[505] Ex. 292, Ferguson True-Up Rebuttal, p. 2.
[506] Ex. 65, Lobser True-Up Rebuttal, p. 2.
[507] Ex. 292, Ferguson True-Up Rebuttal, p. 2.
[508] Ex. 294, Patterson True-Up Direct, p. 2.
[509] Ex. 294, Patterson True-Up Direct, p. 2.
[510] Ex. 294, Patterson True-Up Direct, p. 2.
[511] Ex. 438, Robinett True-Up Rebuttal, p. 1.

for maintenance expenses. Though Landis & Gyr maintain the communications network and perform rudimentary maintenance on the devices, LAC is responsible for the cost of replacement of the devices and their batteries when they stop working or functioning properly. Landis & Gyr is also responsible for maintenance which is built into the monthly service fee.[512] Spire Missouri based its maintenance costs on a historic failure rate LAC has seen since the system was installed in 2005.[513]

9. Spire Missouri estimates that when all maintenance, replacement, and property tax expenses are combined with the roughly $0.49 in depreciation and capital costs plus the $0.24 Landis & Gyr contract meter rate, the total cost per month of AMR devices is approximately $0.86. This would result in a $0.12 per month reduction in cost for the ratepayer from the $0.98 meter read rate prior to July 1, 2017.[514]

10. Staff opposes including $694,256 (approx. $700,000) as a maintenance expense, because Spire Missouri pays for device replacement (a capital cost) and not routine maintenance which is performed under the contract with Landis & Gyr.[515] Spire Missouri will recover those replacement costs as plant in service at the next general rate proceeding.[516]

Conclusions of Law

A. Subsection 393.230.1, RSMo, empowers the Commission to ascertain valuation of property of any gas corporation. This would include the power to, "ascertain all new construction, extensions and additions to the property of every gas

[512] Ex. 292, Ferguson True-Up Rebuttal, pp. 4-5; and Ex. 287, Response to Data Request 484.
[513] Ex. 65, Lobser True-Up Rebuttal, p. 3; See also, Ex. 292, Ferguson True-Up Rebuttal, p. 4, noting that paragraph 4 of the contract amendment with Landis & Gyr specifies that all maintenance and installation costs are included in the amended contract as Landis & Gyr's responsibility through the year 2024.
[514] Ex. 65, Lobser True-Up Rebuttal, p. 4.
[515] Ex. 292, Ferguson True-Up Rebuttal, p. 4.
[516] Ex. 292, Ferguson True-Up Rebuttal, p. 6.

corporation[.]"

B. Subsection 393.240.2 RSMo, empowers the Commission by order to, "fix the proper and adequate rates of depreciation of the several classes of property of such corporation, person or public utility."

Decision

Spire Missouri directly reduced the cost to ratepayers by choosing to purchase rather than continue to lease the AMR devices. Spire Missouri asserts that savings to LAC's customers will be around one million dollars a year. This one million dollar amount is calculated with the assumption that after recoupment of any cost to acquire the AMR devices ($16.6 million), the company will be allowed to recoup approximately $700,000 in maintenance for the devices, and an estimated $400,000 in property taxes on the devices.[517]

The Commission recognizes that Spire Missouri could have waited to purchase the assets until after the true-up period and have taken advantage of any regulatory lag to retain the savings for its shareholders. Because this purchase occurred outside the test year but before September 30, 2017, it is appropriately a true-up issue. Spire Missouri shall be allowed to recover the $16.6 million cost of the AMR devices. Spire Missouri shall establish Account 397.2 – AMR Devices as a new plant sub-account. Additionally, because of the planned obsolescence of these devices, the Commission finds it is reasonable under these specific facts to authorize the amortization of these assets over 7.5 years.

It is unclear from the record what, if any, maintenance expenses will be incurred by Spire Missouri with regard to the maintenance of the AMR devices given that Landis

[517] A resolution of the property tax issue is set out below.

& Gyr are responsible for maintenance under the terms of the contract. The Commission is of the opinion that any replacement of the AMR device or battery would not be maintenance, but is a capital expenditure that the company will have an opportunity to recoup in its next rate case. However, because of the benefits to the ratepayers presented by this purchase and renegotiation of the AMR contract, and because of the uncertainty as to what actual maintenance expense Spire Missouri will incur related to the AMR devices, the Commission orders a maintenance tracker be established to ascertain Spire Missouri's actual maintenance expense on the AMR devices not covered by the contract and not including replacement of the devices or their batteries for possible recovery in Spire Missouri's next rate case.

B. What is the appropriate amount to include in cost of service to account for property taxes related to the AMR devices?

<u>Findings of Fact</u>

1. As set out above, on July 1, 2017, LAC purchased AMR devices that it previously leased from Landis & Gyr for approximately $16.6 million.[518]

2. Spire Missouri estimates that property taxes for 2018 and beyond will be $400,000 annually.[519] Spire Missouri seeks to recover that amount in this case.

3. Because the property was not purchased until July 2017, no property taxes would be assessed on the AMR devices until January 2018 and will not be due until December 31, 2018.

4. Staff argues it is inappropriate to allow recovery of any amount for property taxes related to the purchase of the AMR devices as they are outside the test

[518] Ex. 65, Lobser True-Up Rebuttal, p. 2.
[519] Ex. 65, Lobser True-Up Rebuttal, p. 3.

year and true-up period and are not known and measurable.[520]

Conclusions of Law

A. Spire Missouri seeks to recover in rates approximately $400,000 that it estimates it will have to pay in property taxes annually on the AMR devices. The standard for if this amount can be recovered in rates in this rate case is whether the amount is known and measurable now.[521]

Decision

The Commission finds that the AMR property taxes will not be due to be paid until December 31, 2018. Thus, these property taxes are beyond the test year and true-up period for this case. Also, to include these property taxes in rates, they must be known and measurable; at this point, they are not. However, given the specific circumstances of this case set out below, including the inclusion of a large income tax reduction to expenses due to the Tax Cuts and Jobs Act (TCJA) being incorporated in this case even though outside the test year and true-up period, the Commission determines that the property tax for AMR devices should be included in the property tax tracker set out elsewhere in this order. Therefore, even though the property tax for the AMR devices will not be included in current rates, they will be tracked for potential recovery in LAC's next rate case as discussed in further detail in the TCJA section of this order.

---

[520] Tr. 2586.

[521] *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service*, ER-2014-0370, 2015 WL 5244724, at *71 (Sept. 2, 2015). *State ex rel. GTE North, Inc. v. Missouri Public Service Commission,* 835 S.W. 2d 356, 368 (Mo App. 1992).

THE COMMISSION ORDERS THAT:

1. The tariff sheets filed by Spire Missouri Inc., then known as Laclede Gas Company, on April 11, 2017, and assigned tariff number YG-2017-0195, are rejected.

2. The tariff sheets filed by Spire Missouri Inc., then known as Laclede Gas Company, on April 11, 2017, and assigned tariff number YG-2017-0196, are rejected.

3. Spire Missouri Inc. is authorized to file tariffs for its Spire Missouri East and Spire Missouri West divisions sufficient to recover revenues as determined by the Commission in this order.

4. The non-unanimous Partial Stipulation and Agreement filed on December 13, 2017 is approved.

5. The Partial Non-unanimous Stipulation and Agreement filed on December 20, 2017, is approved.

6. The Non-Unanimous Stipulation Regarding Revenue Allocation and Non-Residential Rate Design, filed on December 20, 2017, is approved.

7. The non-unanimous Partial Stipulation and Agreement Regarding Low Income Energy Affordability Program filed January 9, 2018, is approved.

8. The parties shall comply with the terms of the above-approved stipulation and agreement.

9. The complaint filed by the Office of the Public Counsel in File No. GC-2016-0297 is denied.

10. The Kansas property tax tracker previously ordered in File No. GR-2014-0007 shall be continued.

11. Spire Missouri Inc. shall provide the Staff of the Missouri Public Service

Commission and the Office of the Public Counsel surveillance data in the format agreed upon and set forth in Attachment 1 of Staff's Initial Post-Hearing Brief on a quarterly basis.

12. Spire Missouri Inc. shall provide the Staff of the Missouri Public Service Commission and the Office of the Public Counsel its general ledger and CC&B subledger on an annual basis, within 60 days of the close of Spire Missouri Inc.'s fiscal year, and shall make both the ledger and subledger available more frequently in the event further support of the surveillance data is needed.

13. A tracker shall be established to account for any other effects (either over- or under-collection in rates) of the TCJA not captured by the current reduction in income tax expense for possible inclusion in rates at Spire Missouri Inc.'s next rate case.

14. A tracker shall be established to defer any amounts in excess ADIT over or under the $11.5 million amount refunded in rates, from the effective date of rates resulting from this case, forward, for possible inclusion in a later Spire Missouri Inc. rate case.

15. A tracker shall be established to account for any amounts of property tax expense, including for the automated meter reading devices that are discussion in this Report and Order, over or under the amounts set out in rates for possible inclusion in Spire Missouri Inc.'s next rate proceeding.

16. This report and order shall become effective on March 3, 2018.

BY THE COMMISSION

Morris L. Woodruff
Secretary

Hall, Chm., Kenney, Rupp, Coleman, and
Silvey, CC., concur.

Dippell, Senior Regulatory Law Judge

Blue Chip Financial Forecasts®

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

Vol. 37, No. 6, June 1, 2018

Wolters Kluwer

BLUE CHIP FINANCIAL FORECASTS®

EXECUTIVE EDITOR:
RANDELL E. MOORE
3663 Madison Ave.
Kansas City, MO 64111
Phone (816) 931-0131
E-mail: *randy.moore@wolterskluwer.com*

Publisher: Dom Cervi

Blue Chip Financial Forecasts® (ISSN: 0741-8345) is published monthly by CCH Incorporated, 76 Ninth Avenue, New York, NY 10011. Printed in the U.S.A.

Subscriptions: $1,595 per year for print delivery of 12 monthly issues. For alternate formats (PDF, Excel, online), multiple-copy rates and site-license agreements call Nelson Pereira in the U.S. at 212-771-0701. You may also contact him at: nelson.pereira@wolterskluwer.com

Permission requests: For information on how to obtain permission to reproduce content, please visit the Wolters Kluwer website at: http://www.wklawbusiness.com/footer-pages/permissions

Purchasing reprints: For customized article reprints, please contact *Wright's Media* at 1-877-652-5295 or go to the *Wright's Media* website at *www.wrightsmedia.com.*

Customer Service: 1-800-234-1660
To Order: 1-800-638-8437
Customer Service Fax: 1-800-901-9075
Email: customer.service@wolterskluwer.com
Web Site:
https://lrus.wolterskluwer.com/corporate/blue-chip/

TABLE OF CONTENTS

June Rate Hike A Virtual Certainty, One Or Two More After That in 2018

Domestic Commentary All but one of our panelists predict the Federal Reserve's Open Market Committee (FOMC) will hike interest rates by a further 25 basis points at it June 12th-13th meeting, according to a special question asked as part of our May 21st-22nd survey. That would represent the second, 25 basis point hike of this year and lift the target range for the federal funds rate to 1.75%-2.00%.

Minutes of the FOMC's May 1st-2nd meeting that were released the day following completion of this month's survey tended to underscore our panelists' expectations of a June rate hike given the statement that "Most participants judged that if incoming information broadly confirmed their economic outlook, it would likely soon be appropriate for the Committee to take another step in removing policy accommodation."

In terms of total tightening in 2018, 4.8% of the panelists now predict the FOMC will hike rates by only 50 basis points this year, 38.1% foresee a total of 75 basis points of increases, while 57.1% forecast that the FOMC will enact a total of 100 basis points of interest rate increases this year. These results differ little from what was predicted by our panelists a month ago.

In 2019, 9.3% of the panelists now forecast only one 25 basis point hike, 32.6% foresee 50 basis points of increases, 32.6% predict 75 basis points of tightening, and 25.6% expect a full 100 basis points of increase in the target federal funds rate. One of our panelists, anticipating a marked weakening of GDP growth and inflation next year, predicts that the FOMC will actually opt to cut interest rates by the end of 2019.

The majority of our panelists' views of expected changes in FOMC policy this year and next continues to align closely with median expectations of FOMC members contained in the March Summary of Economic Projections (SEP). While the median forecast of the so-called "dot plot" had suggested since the December meeting a total of three 25 basis point rate hikes by the end of 2018, the March meeting's mean forecast rose by just enough to almost suggest 100 basis points of tightening this year.

The FOMC's March dot plot also indicated a steeper than previously anticipated trajectory for the federal funds rate in 2019 with the median forecast suggesting three 25 basis point increases next year rather than the previous forecast of slightly more than two. As this month's survey continued to suggest, not quite 60% of our panelists forecast at least 75 basis points of rate hikes in 2019.

At its June meeting, in addition to the widely expected rate hike, the FOMC will release an updated SEP. Currently, few analysts seem to anticipate major changes in the economic outlook or the "dot plot" compared to the SEP issued in March.

Of course, all remains contingent upon how the economy performs. The May FOMC minutes noted that a "temporary period of inflation modestly above 2 percent" would be tolerated by policymakers. If, on the other hand, inflation were to suddenly surge, or instead, begin to retreat from the FOMC's 2.0% target, policymakers would no doubt adjust their plans accordingly. The same would be true if economic growth and employment began to deviate considerably from FOMC members' current expectations.

What might conceivably derail the FOMC's and our panelists' relatively upbeat outlook? Some fear a spike in crude oil prices to $100 per barrel. However, given that the U.S. now is one of the world's leading oil producers the hit to energy consumers could be largely offset by the benefits to the domestic energy industry.

Trade tensions clearly remain a threat. The failure to successfully wrap up NAFTA negotiations, the potential imposition of large tariffs on autos, and continued threats directed at China and our European trading partners all hold the potential to create uncertainty among firms and markets, produce retaliatory action, and stymie growth. Outcomes of U.S. elections this November and the Mueller investigation are wildcards to the outlook. Slower than expected economic growth in Japan and Europe could dampen U.S. export growth and the ascension of Italy's new populist government could usher in a fresh period of political/financial problems in Europe if it chooses to disregard EU mandates and fiscal discipline. Another potential threat is increasing financial stress across a number of emerging market economies including Turkey, Argentina, Venezuela, and Indonesia. You also have to throw in the potential negative outcomes of the current Administration's decisions to scuttle the scheduled summit with North Korea and pull out of the Iranian nuclear accord.

In regard to our panelists' updated outlook for the economy, the consensus predicts real GDP will grow 3.2% (saar) in the current quarter, a marked improvement over the advance estimate from the Bureau of Economic Analysis (BEA) that real GDP grew 2.3% (saar) in Q1 of this year. Growth this quarter is expected to be especially supported by a sharp snapback in consumer spending after personal consumption expenditures grew only 1.1% (saar) in Q1, the slowest quarterly pace since Q2 2013. Real GDP is predicted by the consensus to continue growing at well above trend rates of 3.0% (saar) in Q3 and 2.8% in Q4. The Q2 consensus forecast is 0.1 of a percentage greater than a month ago, the Q3 estimate unchanged, and the Q4 forecast 0.1 of a point less than last month.

In 2019, the consensus predicts the pace of real GDP growth will moderate to 2.5% (saar) in Q1, 2.4% in Q2, and 2.2% in Q3. The only difference in these forecasts from a month earlier was a 0.1 of a percentage point increase in Q1 2019's rate of growth.

Consensus forecasts of inflation this quarter and next inched up slightly over the past month, most likely reflecting the strength in crude oil and related product prices. Thereafter, this month's consensus inflation forecasts look almost identical to those of a month ago.

The Consumer Price Index (saar) is forecast by the consensus to increase 2.2% (saar) this quarter, 2.5% in Q3, and 2.1% in Q4. That would represent a slowdown from the 3.3% (saar) registered in Q4 of last year and the 3.5% (saar) seen in Q1 of this year. However, measured on a year-over-year basis – a better measure of its trend – the CPI was up 2.5% in April from 1.6% in June of last year and the core CPI up 2.1% in April compared to1.7% in June 2017.

The GDP price index is predicted to increase 2.1% (saar) in the current quarter, up 0.1 of a percentage point from last month, but little different than the 2.0% seen in Q1 of this year. In Q3 and Q4 of this year it is forecast by the consensus to register respective increases of 2.2% (saar) and 2.1%, the same as last month. Over the first three quarters of 2019, the GDP price index is forecast to register respective increases of 2.2%, the same as last month with the exception of Q3 that came in 0.1 of a percentage point lower than last month.

Consensus Forecast The consensus continues to predict that real GDP growth will average 3.0% (saar) over the remaining three quarters of 2018, but moderate to 2.4% during the first three quarters of 2019. Job growth will remain healthy and wage gains will gradually increase. Inflation on a y/y basis will continue to inch higher, meeting, and then exceeding somewhat the FOMC's 2.0% target. The FOMC will stick with its interest rate normalization process, most likely hiking rates by a total of 75 to 100 basis points this year and by an additional 50 to 75 basis points in 2019. The Treasury yield curve is expected to flatten further over the next six quarters. While the trade-weighted U.S. dollar has recently moved higher, the consensus suggests further upside movement will be limited *(see page 2)*.

Special Questions On page 14 of this issue are results of our twice-yearly, long-range survey with consensus estimates for the years 2020 through 2024 and averages for the 5-year periods 2020-2024 and 2025-2029.

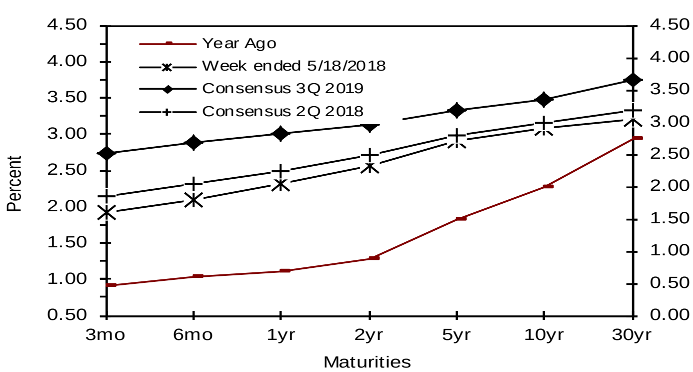
Consensus Forecasts Of U.S. Interest Rates And Key Assumptions[1]

	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Qtr						
Interest Rates	May 18	May 11	May 4	Apr. 27	Apr.	Mar.	Feb.	1Q 2018	2Q 2018	3Q 2018	4Q 2018	1Q 2019	2Q 2019	3Q 2019
Federal Funds Rate	1.70	1.70	1.70	1.70	1.69	1.49	1.42	1.44	**1.7**	**2.0**	**2.2**	**2.4**	**2.6**	**2.8**
Prime Rate	4.75	4.75	4.75	4.75	4.75	4.75	4.50	4.58	**4.8**	**5.0**	**5.2**	**5.4**	**5.6**	**5.8**
LIBOR, 3-mo.	2.33	2.35	2.36	2.36	2.35	2.16	1.84	1.91	**2.3**	**2.4**	**2.6**	**2.8**	**3.0**	**3.1**
Commercial Paper, 1-mo.	1.81	1.79	1.85	1.82	1.82	1.76	1.52	1.59	**1.8**	**2.1**	**2.3**	**2.5**	**2.7**	**2.9**
Treasury bill, 3-mo.	1.92	1.89	1.85	1.85	1.79	1.72	1.56	1.57	**1.9**	**2.0**	**2.2**	**2.4**	**2.6**	**2.7**
Treasury bill, 6-mo.	2.09	2.05	2.03	2.03	1.98	1.91	1.76	1.76	**2.0**	**2.2**	**2.4**	**2.6**	**2.7**	**2.9**
Treasury bill, 1 yr.	2.31	2.27	2.24	2.25	2.15	2.06	1.94	1.93	**2.2**	**2.4**	**2.6**	**2.7**	**2.9**	**3.0**
Treasury note, 2 yr.	2.57	2.52	2.50	2.49	2.38	2.27	2.16	2.15	**2.5**	**2.6**	**2.8**	**2.9**	**3.0**	**3.1**
Treasury note, 5 yr.	2.91	2.82	2.79	2.82	2.70	2.63	2.59	2.53	**2.8**	**2.9**	**3.0**	**3.1**	**3.2**	**3.3**
Treasury note, 10 yr.	3.07	2.97	2.96	2.99	2.86	2.85	2.84	2.75	**3.0**	**3.1**	**3.2**	**3.3**	**3.4**	**3.5**
Treasury note, 30 yr.	3.20	3.13	3.12	3.17	3.07	3.10	3.11	3.02	**3.2**	**3.3**	**3.4**	**3.5**	**3.7**	**3.8**
Corporate Aaa bond	4.16	4.11	4.10	4.11	3.99	3.98	3.91	3.86	**4.1**	**4.3**	**4.4**	**4.6**	**4.7**	**4.8**
Corporate Baa bond	4.83	4.78	4.75	4.73	4.61	4.59	4.47	4.43	**4.8**	**5.0**	**5.2**	**5.3**	**5.5**	**5.6**
State & Local bonds	3.64	3.63	3.67	3.69	3.64	3.61	3.57	3.53	**3.8**	**3.9**	**4.0**	**4.2**	**4.3**	**4.4**
Home mortgage rate	4.66	4.61	4.55	4.55	4.47	4.44	4.33	4.27	**4.6**	**4.7**	**4.8**	**4.9**	**5.1**	**5.1**

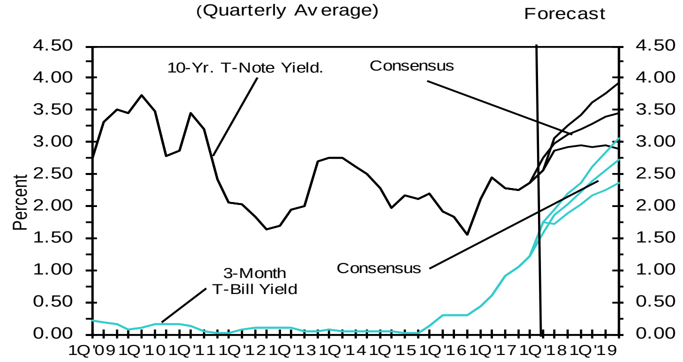
	History								Consensus Forecasts-Quarterly					
Key Assumptions	2Q 2016	3Q 2016	4Q 2016	1Q 2017	2Q 2017	3Q 2017	4Q 2017	1Q 2018	2Q 2018	3Q 2018	4Q 2018	1Q 2019	2Q 2019	3Q 2019
Major Currency Index	89.6	90.3	93.7	94.4	93.0	88.3	88.9	86.1	**87.3**	**87.6**	**87.3**	**87.0**	**87.0**	**87.1**
Real GDP	2.2	2.8	1.8	1.2	3.1	3.2	2.9	2.3	**3.2**	**3.0**	**2.8**	**2.4**	**2.4**	**2.2**
GDP Price Index	2.4	1.4	2.0	2.0	1.0	2.1	2.3	2.0	**2.1**	**2.2**	**2.1**	**2.2**	**2.2**	**2.2**
Consumer Price Index	2.7	1.8	2.7	3.0	0.1	2.1	3.3	3.5	**2.2**	**2.5**	**2.1**	**2.2**	**2.2**	**2.3**

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; LIBOR quotes from Intercontinental Exchange. All interest rate data is sourced from Haver Analytics. Historical data for Fed's Major Currency Index is from FRSR H.10. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).

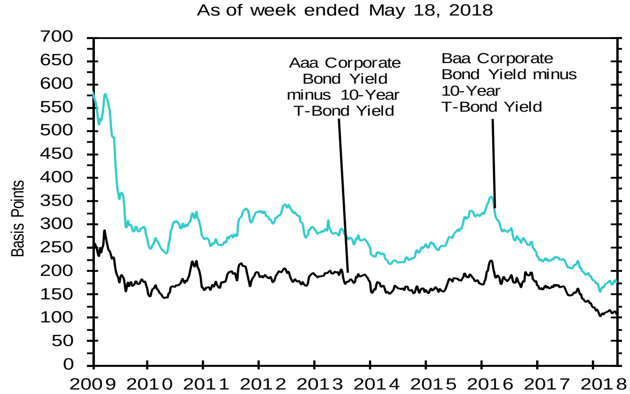
U.S. Treasury Yield Curve
Week ended May 18, 2018 and Year Ago vs. 2Q 2018 and 3Q 2019 Consensus Forecasts



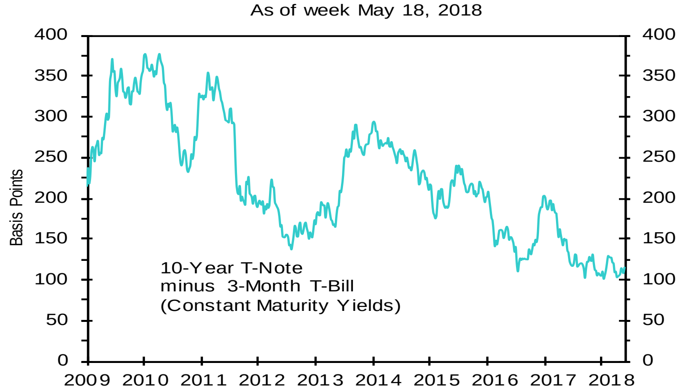
U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield
(Quarterly Average)



Corporate Bond Spreads
As of week ended May 18, 2018



U.S. Treasury Yield Curve
As of week May 18, 2018



3-Month Interest Rates[1]

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	2.32	2.36	1.19	**2.50**	**2.62**	**2.77**
Japan	-0.03	-0.03	-0.01	**0.04**	**0.04**	**0.06**
U.K.	0.64	0.75	0.32	**0.82**	**0.85**	**1.10**
Switzerland	-0.72	-0.73	-0.73	**-0.65**	**-0.65**	**-0.65**
Canada	1.70	1.69	0.81	**1.95**	**2.00**	**2.28**
Australia	2.03	2.14	1.90	**1.90**	**2.05**	**2.40**
Eurozone	-0.33	-0.33	-0.33	**-0.31**	**-0.28**	**-0.12**

10-Yr. Government Bond Yields[2]

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	3.01	2.98	2.27	**3.12**	**3.18**	**3.30**
Germany	0.62	0.63	0.40	**0.73**	**0.86**	**1.04**
Japan	0.03	0.04	0.05	**0.07**	**0.07**	**0.09**
U.K.	1.56	1.59	1.11	**1.70**	**1.81**	**2.00**
France	0.84	0.84	0.84	**1.01**	**1.11**	**1.27**
Italy	2.13	1.78	2.13	**2.19**	**2.27**	**2.19**
Switzerland	0.14	0.18	-0.09	**0.18**	**0.24**	**0.41**
Canada	2.50	2.37	1.48	**2.63**	**2.74**	**2.93**
Australia	2.83	2.87	2.49	**2.89**	**2.98**	**3.05**
Spain	1.25	1.25	1.60	**1.60**	**1.74**	**1.96**

Foreign Exchange Rates[1]

	History			Consensus Forecasts Months From Now:		
	Latest:	Month Ago:	Year Ago:	3	6	12
U.S.	89.005	86.376	92.393	**88.6**	**88.3**	**88.2**
Japan	110.71	107.60	111.47	**108.5**	**108.5**	**109.4**
U.K.	1.3476	1.4033	1.3018	**1.39**	**1.42**	**1.44**
Switzerland	0.9970	0.9744	0.9754	**0.98**	**0.97**	**0.98**
Canada	1.2892	1.2740	1.3537	**1.27**	**1.26**	**1.25**
Australia	0.7511	0.7671	0.7449	**0.76**	**0.76**	**0.77**
Euro	1.1775	1.2282	1.1190	**1.22**	**1.24**	**1.25**

Consensus 3-Month Rates vs. U.S. Rate

	Now	In 12 Mo.
Japan	-2.35	**-2.70**
U.K.	-1.68	**-1.67**
Switzerland	-3.04	**-3.42**
Canada	-0.62	**-0.49**
Australia	-0.29	**-0.37**
Eurozone	-2.65	**-2.88**

Consensus 10-Year Gov't Yields vs. U.S. Yield

	Now	In 12
Germany	-2.39	**-2.26**
Japan	-2.98	**-3.22**
U.K.	-1.45	**-1.31**
France	-2.17	**-2.04**
Italy	-0.88	**-1.12**
Switzerland	-2.87	**-2.89**
Canada	-0.51	**-0.38**
Australia	-0.18	**-0.25**
Spain	-1.76	**-1.35**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Three month rate on interest-earning money market deposits denominated in selected currencies. [2]Government bonds are yields to maturity. Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's Major Currency Index.

International Commentary Financial market participants have tended to write-off the unanticipated growth slowdown in developed market (DM) economies during Q1 of this year, expecting the pace of GDP growth to rebound smartly in Q2, and along with it, firmer in inflation. To date, however, signs of a truly sharp bounce back in growth or inflation have failed to materialize. Analysts still look for the pace of global GDP growth in Q2 to easily exceed that seen in Q1, but some have begun to trim their estimates. As a result, expectations of when and how much central banks in some DM nations move to normalize their accommodative monetary policies are shifting.

The situation in emerging market (EM) economies looks even more troubling as rising geopolitical uncertainty, higher oil prices, and a stronger U.S. dollar weigh on their asset prices and currencies. Particularly troubling over the past month have been developments in Argentina and Turkey whose currencies have been in freefall.

Real GDP in the Eurozone grew only 1.7% (ar) in Q1, a full percentage point slower than in Q4. A harsh winter in Northern Europe and strikes in Germany and France likely contributed to the slowdown. Currently, consensus expectations have GDP growth in the Eurozone bouncing back to almost 3.0% (ar) in Q2, before registering second half 2018 growth of about 2.4%. However, May's flash composite PMI reading for currency bloc slipped for a fourth month to an 18-month low as business activity and new orders growth slowed. Consumer price inflation in the Eurozone, too, has pulled back. Its y/y rate slipped to 1.2% in April from 1.3% in March and the y/y rate of the core CPI fell 0.3 of a percentage point to 0.7%.

While most analysts still believe the European Central Bank will begin to taper the size of, if not completely end, its asset purchase program by the end of this year, fewer now appear to think the ECB will hike its deposit rate by the middle of 2019. Further complicating ECB policy is lingering trade tensions with the U.S. and developments in Italy where the populist Five-Star Movement has formed a coalition government with the anti-immigration League Party. The potential failure by Italy to uphold its EU commitments on fiscal discipline has sent its 10-year note yields sharply higher and could reignite fears of capital flight in Southern Europe, further roiling financial markets.

The Bank of England's Monetary Policy Committee left rates unchanged at its May 10th meeting after real GDP grew only 0.4% (ar) in Q1, the slowest pace in five years. Snowy weather likely contributed to the slowdown in GDP, but cannot explain all of the softness. Indeed, retail sales were weak in April, suggesting that personal consumption in Q2 may undershoot expectations. Nonetheless, most analysts look for GDP growth to rebound to about 2.0% over the remainder of this year. While BoE governor Mark Carney has stated that an interest rate increase this year "is likely", soft growth, Brexit uncertainties, and inflation that is falling faster than expected, has markets scaling back expectations for when and how much the MPC may hike rates over coming quarters. The y/y change in consumer price inflation fell to 2.4% in April, the lowest since March 2017, but higher energy prices may keep it from falling further in the near-term.

Real GDP in Japan contracted a worse-than-expected 0.6% (ar) in Q1, ending a nine-quarter streak of increases. Moreover, Q4's growth rate was slashed to 0.6% from 1.6% and May's flash manufacturing PMI fell to 52.5 from 53.8 in April as new orders growth dropped to a nine-month low. At its April meeting the Bank of Japan left policy unchanged, but dropped its timeline for achieving 2.0% inflation. Underscoring the BoJ's failure to push inflation higher, the y/y change in the core CPI fell for a second, straight month in April to 0.7%.

The Bank of Canada is expected to leave policy unchanged at its late-May meeting. The economy is running close to capacity, but inflation slipped back to 2.2% in April. According to the BoC, higher interest rates will likely be warranted over time, but some policy accommodation still will be required to keep inflation on track. Most analysts look for two more quarter point hikes in rates this year and more in 2019 *(see pages 10-11 for individual panelists' forecasts).*

Second Quarter 2018

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.
	Federal Funds Rate	Prime Bank Rate	LIBOR Rate 3-Mo.	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Major Currency $ Index	Real GDP	GDP Price Index	Cons. Price Index
Scotiabank Group	2.0 H	5.0 H	na	na	2.1 H	na	na	2.6 H	2.8	3.0	3.1	na	na	na	na	na	2.5	2.0	2.4
ACIMA Private Wealth	1.9	4.9	2.4	2.0 H	1.9	2.1 H	2.2	2.6 H	2.9 H	3.0	3.2	4.0	4.9	3.9	4.6	85.5 L	2.2 L	2.3	3.0
Swiss Re	1.9	4.9	2.2	1.9	1.8	1.9	2.1	2.3 L	2.5 L	2.8	3.1	4.1	5.0	na	4.6	na	4.0	2.3	1.0 L
J.P. Morgan Chase	1.9	na	2.3	na	na	na	na	2.5	2.8	3.0	3.2	na	na	na	na	na	2.3	2.0	1.8
Bank of America Merrill Lynch	1.9	na	2.4	na	2.0	na	na	2.5	2.9 H	3.0	3.2	na	na	na	na	na	3.2	1.9	2.0
RBC Capital Markets	1.9	na	na	na	na	na	na	2.5	2.8	3.0	3.2	na	na	na	na	na	3.7	2.2	3.0
BNP Paribas Americas	1.9	na	2.1	na	na	na	na	2.5	2.9 H	3.1 H	na	na	na	na	na	na	4.2 H	na	1.1
Barclays	1.9	5.0 H	na	na	na	na	na	2.4	2.6	2.8 L	3.0 L	na	na	na	na	na	3.0	2.1	1.6
MacroFin Analytics	1.8	4.8	2.4	1.8	1.9	2.1 H	2.3	2.6 H	2.9 H	3.1 H	3.2	4.1	4.9	3.8	4.6	89.1 H	2.9	1.8	1.4
Action Economics	1.8	4.8	1.9	1.9	1.9	2.1 H	2.3	2.6 H	2.9 H	3.0	3.2	4.1	4.8	3.7	4.5	86.1	3.6	2.7	1.8
Daiwa Capital Markets America	1.8	4.8	2.4	1.9	1.9	2.1 H	2.2	2.5	2.9 H	3.0	3.3	4.1	4.9	na	4.6	87.0	3.1	2.0	2.0
Amherst Pierpont Securities	1.8	4.8	2.4	1.9	1.9	2.1 H	2.3	2.5	2.8	3.0	3.2	4.0	4.8	3.9	4.6	88.5	3.9	2.3	2.0
Nomura Securities, Inc.	1.8	4.8	na	na	na	na	na	2.5	2.8	3.0	na	4.1	4.7	na	na	na	3.1	1.9	2.1
Via Nova Investment Mgt.	1.8	4.8	2.3	1.7 L	1.7 L	1.8	2.1	2.4	2.8	2.9	3.2	4.1	4.6 L	3.8	4.6	86.8	3.2	2.0	2.3
Goldman Sachs & Co.	1.8	na	2.2	na	1.7 L	na	na	2.3 L	2.7	2.9	3.1	na	na	na	4.4 L	na	3.5	2.1	2.3
AIG	1.8	4.8	na	na	1.8	2.0	2.4 H	2.4	2.7	2.9	3.1	na	4.7	na	4.5	na	3.3	2.1	2.5
Societe Generale	1.7	4.8	na	na	1.9	na	na	2.5	na	2.9	3.0 L	na	na	na	na	na	2.6	2.0	1.6
Grant Thornton/Diane Swonk	1.7	4.8	2.1	1.9	2.0	2.1 H	2.3	2.6 H	2.9 H	3.0	3.2	3.5 L	4.8	3.4 L	4.6	88.5	2.9	1.7	1.8
NatWest Markets	1.7	4.8	2.4	1.8	1.8	2.0	2.2	2.4	2.8	3.0	3.2	4.3	4.9	3.8	4.8 H	87.0	3.3	1.7	2.0
DePrince & Assoc.	1.7	4.8	2.4	1.9	1.9	2.1 H	2.3	2.5	2.8	3.0	3.1	4.0	4.8	3.9	4.6	87.6	2.8	1.9	2.0
Regions Financial Corporation	1.7	4.7 L	2.4	1.8	1.9	2.1 H	2.3	2.5	2.8	3.0	3.2	4.2	4.9	3.9	4.6	87.2	3.3	2.0	2.9
Loomis, Sayles & Company	1.7	4.8	2.4	1.9	1.9	2.1 H	2.2	2.4	2.8	3.0	3.2	4.0	4.8	3.7	4.5	86.7	3.0	1.9	2.0
Fannie Mae	1.7	4.8	na	na	1.9	2.1 H	2.3	2.5	2.8	3.0	3.2	na	na	na	4.6	na	2.8	1.8	1.9
BMO Capital Markets	1.7	4.8	2.4	na	1.9	2.1 H	2.3	2.5	2.8	3.0	3.2	na	na	na	4.6	87.5	2.8	1.8	2.0
Economist Intelligence Unit	1.7	4.7 L	1.7 L	1.9	1.9	2.1 H	2.3	2.5	2.9 H	3.1 H	3.3	na	na	na	4.7	na	3.0	na	2.2
Moody's Analytics	1.7	4.8	2.3	1.8	1.8	1.9	2.2	2.4	2.7	3.1 H	3.5 H	4.2	5.1 H	3.5	4.6	na	3.5	2.8	3.5
Naroff Economic Advisors	1.7	4.8	2.4	1.9	1.9	2.1 H	2.3	2.5	2.8	3.0	3.3	4.4 H	5.0	4.0	4.6	87.6	3.3	2.6	3.7 H
S&P Global	1.7	5.0	2.1	na	1.7 L	1.9	2.2	2.4	2.7	3.0	3.2	na	na	na	4.4 L	86.1	3.4	2.8	1.6
Wells Fargo	1.7	4.7	2.3	1.8	2.0	2.1 H	2.2	2.6 H	2.9 H	3.1 H	3.2	4.3	5.0	3.8	4.7	86.3	3.3	2.0	1.7
Cycledata Corp.	1.7	4.8	2.2	1.7 L	1.8	2.0	2.2	2.4	2.7	2.9	3.1	4.0	4.8	3.7	4.6	87.0	3.2	2.0	1.9
Georgia State University	1.7	4.8	na	na	1.8	2.0	2.3	2.6 H	2.9 H	3.1 H	3.2	4.1	4.8	na	4.6	na	3.8	1.5	2.0
Chase Wealth Management	1.7	4.8	2.3	2.0	1.9	2.1 H	2.3	2.5	2.7	3.1 H	3.3	4.1	4.9	3.9	4.7	89.1	3.0	2.0	2.1
RDQ Economics	1.7	4.8	2.2	1.8	1.9	2.1 H	2.3	2.5	2.7	2.9	3.1	4.0	4.8	3.8	4.5	87.5	2.6	2.2	2.2
MUFG Union Bank	1.7	4.8	2.3	1.8	1.8	2.0	2.2	2.5	2.8	3.0	3.2	3.9	4.7	3.8	4.6	88.0	3.0	2.1	3.2
Nat'l Assn. of Realtors	1.7	4.7 L	na	1.8	1.9	2.1 H	2.3	2.5	2.8	3.0	3.1	4.0	4.7	na	4.5	na	2.9	2.2	3.2
PNC Financial Services Corp.	1.7	4.8	2.4	na	1.9	2.1 H	2.3	2.5	2.8	3.0	3.2	na	4.8	4.0 H	4.6	86.6	3.6	3.2 H	3.1
Comerica Bank	1.7	4.8	2.4	na	1.9	2.1 H	2.3	2.5	2.8	3.0	3.2	na	na	na	4.6	na	3.5	2.0	3.2
The Northern Trust Company	1.7	4.8	2.5 H	1.8	1.9	2.1 H	2.3	2.5	2.8	3.0	3.3	4.0	4.8	3.7	4.6	85.9	3.3	2.0	2.0
Chmura Economics & Analytics	1.7	4.8	2.4	1.8	1.8	2.0	2.2	2.5	2.8	2.9	3.1	4.0	na	na	4.5	87.8	2.5	2.0	2.2
Moody's Capital Markets Group	1.7	4.8	2.4	1.9	1.9	2.1 H	2.3	2.5	2.8	3.0	3.1	4.0	4.7	3.7	4.6	88.0	2.9	2.1	1.9
High Frequency Economics	1.7	4.8	na	na	1.7 L	1.9	2.1	2.6 H	2.7	2.8 L	3.1	na	na	na	na	na	3.7	2.0	2.0
GLC Financial Economics	1.7	4.8	2.3	1.8	1.8	2.0	2.1	2.4	2.7	2.9	3.0 L	4.0	4.6 L	3.5	4.4 L	88.8	3.3	2.4	3.3
Oxford Economics	1.7	4.8	2.4	na	1.8	2.0	2.2	2.5	2.8	3.0	3.3	na	na	na	4.6	87.6	3.6	1.4 L	1.9
Stone Harbor Investment Partners	1.6 L	4.8	2.2	2.0 H	1.7 L	1.8 L	2.0 L	2.3 L	2.8	3.0	3.2	4.2	5.0	na	4.6	86.0	3.0	2.4	1.7
June Consensus	**1.7**	**4.8**	**2.3**	**1.8**	**1.9**	**2.0**	**2.2**	**2.5**	**2.8**	**3.0**	**3.2**	**4.1**	**4.8**	**3.8**	**4.6**	**87.3**	**3.2**	**2.1**	**2.2**
Top 10 Avg.	1.9	4.9	2.4	1.9	1.9	2.1	2.3	2.6	2.9	3.1	3.3	4.2	4.9	3.9	4.6	88.3	3.8	2.6	3.2
Bottom 10 Avg.	1.7	4.7	2.1	1.8	1.7	1.9	2.1	2.4	2.7	2.9	3.1	3.9	4.7	3.6	4.5	86.3	2.6	1.7	1.5
May Consensus	1.7	4.8	2.3	1.8	1.8	2.0	2.2	2.4	2.7	2.9	3.2	4.0	4.8	3.8	4.5	86.6	3.1	2.0	1.9
Number of Forecasts Changed From A Month Ago:																			
Down	4	5	7	7	3	1	1	2	2	5	6	8	8	8	6	4	9	8	12
Same	30	27	16	10	13	11	9	10	12	12	20	8	8	6	7	8	18	21	12
Up	10	7	11	9	23	23	25	32	28	27	16	11	11	7	22	14	17	13	20
Diffusion Index	57 %	53 %	56 %	54 %	76 %	81 %	84 %	84 %	81 %	75 %	62 %	56 %	56 %	48 %	73 %	69 %	59 %	56 %	59 %

Third Quarter 2018

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)		
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	A.	B.	C.	D.
	Federal Funds Rate	Prime Bank Rate	LIBOR Rate 3-Mo.	Com. Paper 1-Mo.	Treas. Bills 3-Mo.	Treas. Bills 6-Mo.	Treas. Bills 1-Yr.	Treas. Notes 2-Yr.	Treas. Notes 5-Yr.	Treas. Notes 10-Yr.	Treas. Bond 30-Yr.	Aaa Corp. Bond	Baa Corp. Bond	State & Local Bonds	Home Mtg. Rate	Fed's Major Currency $ Index	Real GDP	GDP Price Index	Cons. Price Index
ACIMA Private Wealth	2.3 H	5.3 H	2.5	2.3 H	2.3 H	2.4 H	2.4	2.6	2.8	2.8 L	3.1	4.0	4.9	3.9	4.5	85.5	3.2	1.4	1.0 L
Scotiabank Group	2.3 H	5.3 H	na	na	2.3 H	na	na	2.6	2.9	3.0	3.2	na	na	na	na	na	2.5	2.5	2.4
Bank of America Merrill Lynch	2.1	na	2.6 H	na	2.2	na	na	2.7	3.1 H	3.2	3.3	na	na	na	na	na	3.6	1.9	2.5
J.P. Morgan Chase	2.1	na	2.5	na	na	na	na	2.7	3.0	3.1	3.2	na	na	na	na	na	2.5	2.3	3.0
Swiss Re	2.1	5.1	2.3	2.1	2.0	2.1	2.2	2.4 L	2.6 L	2.9	3.3	4.6	5.5	na	4.7	na	2.5	3.7 H	3.7
RBC Capital Markets	2.1	na	na	na	na	na	na	2.7	3.0	3.2	3.5	na	na	na	na	na	2.8	1.3 L	4.2 H
BNP Paribas Americas	2.1	na	2.3	na	na	na	na	2.6	3.0	3.2	na	na	na	na	na	na	3.5	na	2.3
Barclays	2.1	5.3 H	na	na	na	na	na	2.5	2.7	2.8 L	3.0 L	na	na	na	na	na	3.5	2.5	3.0
Moody's Analytics	2.0	5.1	2.4	2.0	1.9	2.1	2.4	2.6	3.0	3.3	4.0 H	4.8 H	5.7 H	3.9	4.8	na	3.5	2.4	2.1
Chase Wealth Management	2.0	5.0	2.4	2.2	2.1	2.3	2.5	2.7	2.9	3.2	3.5	4.3	5.1	4.1	4.8	89.2	2.9	2.1	2.2
Via Nova Investment Mgt.	2.0	5.0	2.5	1.9 L	1.9	2.1	2.3	2.7	3.1 H	3.3	3.5	4.4	4.9	4.2 H	4.9	87.0	3.1	2.1	2.3
Goldman Sachs	2.0	na	2.3	na	1.9	na	na	2.5	2.9	3.2	3.4	na	na	na	4.4 L	na	3.0	2.6	3.0
Nomura Securities, Inc.	2.0	5.0	na	na	na	na	na	2.8 H	3.0	3.3	na	4.3	4.8	na	na	na	3.4	2.1	3.5
NatWest Markets	2.0	5.1	2.5	2.0	2.1	2.3	2.5	2.7	3.0	3.3	3.4	4.6	5.2	3.9	5.0 H	89.0	2.7	2.0	2.7
Amherst Pierpont Securities	2.0	5.1	2.6 H	2.1	2.1	2.3	2.5	2.7	3.0	3.3	3.5	4.3	5.2	4.1	4.9	89.5	3.2	2.4	3.0
BMO Capital Markets	2.0	5.1	2.6 H	na	2.1	2.3	2.5	2.7	3.0	3.2	3.3	na	na	na	4.8	86.7	2.9	2.2	2.4
Action Economics	2.0	5.1	2.3	2.1	2.1	2.1	2.4	2.6	2.9	3.1	3.3	4.2	5.0	3.8	4.7	87.7	3.4	2.3	2.4
Societe Generale	2.0	5.0	na	na	2.1	na	na	2.6	na	3.0	3.1	na	na	na	na	na	2.3 L	2.0	1.8
DePrince & Associates	2.0	5.0	2.4	2.1	2.1	2.2	2.5	2.7	3.0	3.1	3.3	4.2	5.1	4.0	4.8	89.0	3.1	2.1	2.2
MUFG Union Bank	2.0	5.0	2.5	1.9 L	2.0	2.1	2.3	2.6	2.9	3.0	3.4	4.0	4.8	3.9	4.6	87.0	3.1	1.7	2.6
Loomis, Sayles & Company	1.9	5.0	2.5	2.1	2.1	2.2	2.4	2.5	2.8	3.1	3.3	4.1	4.8	3.8	4.6	87.1	3.3	1.9	2.3
MacroFin Analytics	1.9	5.0	2.6 H	2.0	2.1	2.3	2.5	2.7	3.1 H	3.3	3.4	4.2	5.1	4.0	4.8	89.3	2.8	2.2	2.3
Economist Intelligence Unit	1.9	5.0	2.0 L	2.1	2.1	2.2	2.4	2.7	3.0	3.2	3.4	na	na	na	4.8	na	2.4	na	2.3
Grant Thornton/Diane Swonk	1.9	5.0	2.3	2.1	2.2	2.3	2.6 H	2.8 H	3.0	3.2	3.3	3.7 L	4.9	3.5 L	4.8	89.9 H	3.2	2.0	2.8
The Northern Trust Company	1.9	5.1	2.5	2.0	2.1	2.2	2.4	2.6	3.0	3.2	3.5	4.4	5.1	4.0	4.8	85.5	2.9	2.3	2.3
S&P Global	1.9	5.0	2.2	na	1.9	2.1	2.3	2.5	2.8	3.1	3.4	na	na	na	4.4 L	84.6 L	3.9 H	2.5	1.9
High Frequency Economics	1.9	5.0	na	na	2.0	2.1	2.3	2.7	2.8	3.0	3.3	na	na	na	na	na	3.0	2.2	2.2
AIG	1.9	5.0	na	na	1.9	2.2	2.5	2.6	2.9	3.1	3.4	na	4.9	na	4.6	na	2.4	2.1	2.4
Regions Financial Corporation	1.9	4.9	2.5	2.0	2.0	2.2	2.4	2.6	3.0	3.1	3.3	4.3	5.0	4.1	4.7	87.8	3.0	2.1	2.4
Oxford Economics	1.9	5.2	2.6 H	na	1.9	2.1	2.3	2.6	2.8	3.1	3.4	na	na	na	4.8	86.8	2.6	1.8	2.1
Chmura Economics & Analytics	1.9	5.0	2.6 H	2.0	2.1	2.3	2.5	2.7	3.0	3.1	3.3	4.2	na	na	4.7	88.2	2.8	2.0	2.2
Comerica Bank	1.9	5.0	2.6 H	na	2.1	2.3	2.4	2.7	3.0	3.2	3.4	na	na	na	4.8	na	2.8	2.0	2.6
Wells Fargo	1.9	4.9	2.4	2.0	2.2	2.3	2.4	2.7	3.0	3.2	3.3	4.4	5.1	3.9	4.8	88.0	3.2	1.9	2.1
Daiwa Capital Markets America	1.9	5.0	2.5	2.0	2.0	2.2	2.3	2.7	3.0	3.2	3.4	4.2	5.0	na	4.8	88.0	2.7	2.0	2.2
Cycledata Corp.	1.9	5.0	2.3	2.0	1.9	2.1	2.3	2.5	2.8	3.0	3.3	4.2	5.0	4.0	4.7	87.0	2.9	2.1	2.2
RDQ Economics	1.9	5.0	2.3	2.0	2.0	2.2	2.4	2.6	2.8	3.0	3.2	4.2	5.0	3.9	4.6	88.8	2.6	2.2	2.3
Naroff Economic Advisors	1.9	5.0	2.5	2.1	2.1	2.3	2.5	2.6	3.0	3.2	3.4	4.6	5.3	4.2 H	4.9	86.3	3.1	2.4	3.0
PNC Financial Services Corp.	1.9	5.0	2.6 H	na	2.1	2.3	2.5	2.8 H	3.0	3.2	3.5	na	5.1	4.2 H	4.7	86.8	3.1	1.9	1.9
Moody's Capital Markets Group	1.9	5.0	2.6	2.1	2.1	2.3	2.4	2.6	2.8	3.0	3.1	4.0	4.7 L	3.6	4.7	88.8	2.7	2.0	2.1
Georgia State University	1.9	5.0	na	na	1.9	2.2	2.4	2.7	3.1 H	3.4 H	3.6	4.5	5.2	na	4.8	na	3.0	2.3	2.8
GLC Financial Economics	1.9	4.9	2.4	2.0	2.0	2.2	2.4	2.6	2.9	3.1	3.2	4.4	5.0	3.7	4.7	88.5	3.4	2.2	2.9
Fannie Mae	1.9	5.0	na	na	2.3 H	2.4 H	2.5	2.7	3.0	3.1	3.2	na	na	na	4.7	na	2.9	2.7	2.9
Stone Harbor Investment Partners	1.9	5.0	2.4	2.2	1.8 L	1.9 L	2.1 L	2.5	2.9	3.2	3.5	4.4	5.2	na	4.8	85.0	3.2	2.4	2.0
Nat'l Assn. of Realtors	1.8 L	4.8 L	na	1.9 L	2.0	2.2	2.4	2.6	2.9	3.1	3.3	4.2	5.0	na	4.6	na	3.0	2.3	3.3
June Consensus	**2.0**	**5.0**	**2.4**	**2.1**	**2.0**	**2.2**	**2.4**	**2.6**	**2.9**	**3.1**	**3.3**	**4.3**	**5.0**	**3.9**	**4.7**	**87.6**	**3.0**	**2.2**	**2.5**
Top 10 Avg.	2.1	5.2	2.6	2.1	2.2	2.3	2.5	2.7	3.0	3.3	3.5	4.5	5.3	4.1	4.8	89.0	3.5	2.6	3.3
Bottom 10 Avg.	1.9	4.9	2.2	2.0	1.9	2.1	2.3	2.5	2.8	2.9	3.1	4.1	4.9	3.8	4.6	86.1	2.5	1.8	1.9
May Consensus	2.0	5.0	2.4	2.1	2.0	2.2	2.3	2.6	2.9	3.1	3.3	4.2	5.0	3.9	4.7	86.7	3.0	2.2	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	5	4	4	5	5	5	3	2	2	3	11	8	5	5	3	2	11	8	3
Same	32	29	19	12	16	11	9	13	13	19	18	8	11	6	12	7	26	21	17
Up	7	6	11	8	18	19	23	29	28	22	13	10	11	10	20	18	7	13	24
Diffusion Index	52 %	53 %	60 %	56 %	67 %	70 %	79 %	81 %	80 %	72 %	52 %	54 %	61 %	62 %	74 %	80 %	45 %	56 %	74 %

Fourth Quarter 2018

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For ---Qtr.---	(Q-Q % Change) (SAAR)		
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
RBC Capital Markets	2.4 H	na	na	na	na	na	na	2.8	3.1	3.3	3.6	na	na	na	na	na	2.8	2.2	0.5 L
Swiss Re	2.4 H	5.4	2.5	2.3	2.2	2.4	2.5	2.6	2.7	2.9	3.4	4.7	5.6	na	4.8	na	2.8	0.7 L	1.6
J.P. Morgan Chase	2.4 H	na	2.7	na	na	na	na	2.8	3.0	3.1	3.2	na	na	na	na	na	2.5	2.1	2.3
Barclays Capital	2.4 H	5.5 H	na	na	na	na	na	2.6	2.7	2.8	3.0	na	na	na	na	na	3.0	2.1	2.0
BNP Paribas Americas	2.4 H	na	2.5	na	na	na	na	2.7	3.1	3.2	na	na	na	na	na	na	3.0	na	2.4
Moody's Analytics	2.4 H	5.5 H	2.7	2.3	2.2	2.3	2.7	2.9	3.3	3.6 H	4.3 H	5.2 H	6.1 H	4.1	5.1 H	na	3.2	3.0 H	2.3
ACIMA Private Wealth	2.3	5.3	2.6	2.5 H	2.3	2.4	2.4	2.4 L	2.6 L	2.5 L	2.9	4.0	4.9	3.9	4.3 L	84.5	2.5	2.1	1.6
Goldman Sachs & Co.	2.3	na	2.6	na	2.2	na	na	2.6	3.1	3.2	3.5	na	na	na	4.6	na	2.5	1.8	2.0
Scotiabank Group	2.3	5.3	na	na	2.3	na	na	2.7	2.9	3.1	3.2	na	na	na	na	na	2.4	2.5	2.4
Nomura Securities, Inc.	2.3	5.3	na	na	na	na	na	3.0 H	3.1	3.3	na	4.3	4.8	na	na	na	3.4 H	2.1	2.6
NatWest Markets	2.2	5.3	2.7	2.3	2.3	2.5	2.7	2.9	3.2	3.3	3.5	4.6	5.3	4.0	5.1 H	90.0	3.0	2.0	1.8
DePrince & Assoc.	2.2	5.2	2.6	2.4	2.3	2.5	2.7	2.9	3.1	3.3	3.4	4.4	5.5	4.3	4.9	89.4	2.9	2.2	2.3
MacroFin Analytics	2.2	5.3	2.8 H	2.3	2.4	2.6	2.8 H	3.0 H	3.4 H	3.5	3.7	4.5	5.4	4.3	5.0	89.6	2.7	2.2	2.3
BMO Capital Markets	2.2	5.3	2.7	na	2.3	2.4	2.6	2.8	3.1	3.2	3.4	na	na	na	4.9	85.2	2.9	2.2	2.4
Amherst Pierpont Securities	2.2	5.3	2.8 H	2.3	2.3	2.5	2.7	2.9	3.2	3.5	3.8	4.7	5.5	4.4 H	5.1 H	90.5	3.2	2.5	3.0
Wells Fargo	2.2	5.2	2.6	2.2	2.4	2.5	2.6	2.8	3.1	3.3	3.4	4.5	5.2	4.0	4.8	86.8	3.1	2.0	2.0
S&P Global	2.2	5.2	2.4	na	2.1	2.3	2.4	2.7	2.9	3.2	3.5	na	na	na	4.6	84.3	3.1	2.1	2.0
Chase Wealth Management	2.2	5.3	2.6	2.5	2.3	2.5	2.7	2.8	3.0	3.3	3.6	4.4	5.2	4.2	4.9	89.1	2.8	2.2	2.1
Daiwa Capital Markets America	2.2	5.3	2.7	2.3	2.3	2.4	2.6	2.9	3.2	3.3	3.6	4.4	5.2	na	5.0	89.0	2.6	2.2	2.3
RDQ Economics	2.2	5.3	2.6	2.3	2.4	2.6 H	2.7	2.7	3.0	3.2	3.4	4.6	5.3	4.0	4.8	90.1	2.4	2.3	2.3
Naroff Economic Advisors	2.2	5.3	2.6	2.3	2.4	2.6	2.7	2.8	3.1	3.3	3.6	4.8	5.5	4.4 H	5.1 H	84.5	2.6	2.6	2.9
MUFG Union Bank	2.2	5.3	2.6	2.2	2.2	2.3	2.6	2.7	3.0	3.1	3.5	4.1	4.9	4.0	4.7	82.0 L	3.3	2.1	3.3 H
Societe Generale	2.2	5.3	na	na	2.2	na	na	2.8	na	3.0	3.1	na	na	na	na	na	2.3	2.0	1.7
The Northern Trust Company	2.2	5.3	2.6	2.3	2.3	2.4	2.6	2.8	3.1	3.4	3.7	4.7	5.5	4.3	5.0	84.7	3.0	2.2	2.2
High Frequency Economics	2.2	5.3	na	na	2.2	2.4	2.6	2.8	3.0	3.1	3.4	na	na	na	na	na	2.8	2.3	2.3
Regions Financial Corporation	2.2	5.2	2.6	2.1	2.2	2.3	2.5	2.7	3.1	3.2	3.5	4.5	5.1	4.2	4.8	88.1	2.9	1.9	2.1
Chmura Economics & Analytics	2.2	5.3	2.8	2.3	2.3	2.5	2.7	2.9	3.1	3.3	2.6 L	4.3	na	na	4.8	88.1	2.9	2.1	2.2
Economist Intelligence Unit	2.2	5.2	2.2 L	2.3	2.3	2.4	2.6	2.9	3.2	3.4	3.6	na	na	na	5.0	na	2.2 L	na	2.2
Grant Thornton/Diane Swonk	2.2	5.2	2.6	2.4	2.2	2.5	2.8 H	3.0 H	3.2	3.4	3.6	3.9 L	5.1	3.5 L	4.9	90.7 H	2.9	2.2	1.1
Oxford Economics	2.2	5.3	2.7	na	2.0	2.3	2.4	2.6	2.9	3.2	3.5	na	na	na	4.8	85.1	2.5	2.0	1.9
Loomis, Sayles & Company	2.1	5.2	2.7	2.3	2.3	2.4	2.5	2.6	2.8	3.1	3.4	4.1	4.9	3.8	4.6	87.2	3.4 H	2.4	2.1
Action Economics	2.1	5.3	2.4	2.3	2.2	2.2	2.5	2.6	2.9	3.2	3.3	4.2	5.0	3.7	4.8	87.8	3.2	2.2	2.3
Bank of America Merrill Lynch	2.1	na	2.6	na	2.3	na	na	2.8	3.2	3.3	3.3	na	na	na	na	na	3.1	1.8	2.4
Comerica Bank	2.1	5.2	2.7	na	2.2	2.3	2.5	2.7	3.1	3.2	3.5	na	na	na	4.9	na	3.0	2.0	2.6
Stone Harbor Investment Partners	2.1	5.3	2.6	2.4	2.0	2.1 L	2.3 L	2.6	3.0	3.4	3.6	4.6	5.4	na	5.0	84.0	2.8	2.4	2.3
GLC Financial Economics	2.1	5.1	2.5	2.2	2.2	2.4	2.5	2.7	3.1	3.3	3.4	4.5	5.1	3.9	4.8	88.0	3.0	2.0	2.5
Via Nova Investment Mgt.	2.1	5.1	2.6	2.0 L	2.0	2.1 L	2.4	2.7	3.2	3.3	3.6	4.5	4.9	4.3	4.9	87.0	3.0	2.2	2.3
AIG	2.0	5.0 L	na	na	1.9	2.3	2.6	2.7	3.0	3.2	3.5	na	4.9	na	4.7	na	2.7	2.1	1.9
Nat'l Assn. of Realtors	2.0	5.0 L	na	2.1	2.2	2.3	2.5	2.7	3.0	3.2	3.4	4.3	5.1	na	4.7	na	3.1	2.4	3.2
Georgia State University	1.9 L	5.0 L	na	na	1.9 L	2.3	2.5	2.8	3.3	3.5	3.8	4.7	5.4	na	5.0	na	2.4	2.3	1.9
Moody's Capital Markets Group	1.9 L	5.0 L	2.6	2.2	2.2	2.3	2.4	2.5	2.8	2.9	3.1	3.9 L	4.7 L	3.5 L	4.6	89.4	2.4	1.9	1.5
Fannie Mae	1.9 L	5.0 L	na	na	2.5 H	2.6 H	2.7	2.8	3.0	3.1	3.2	na	na	na	4.7	na	2.7	2.3	0.9
PNC Financial Services Corp.	1.9 L	5.0 L	2.7	na	2.2	2.4	2.6	2.8	3.1	3.3	3.6	na	5.2	4.2	4.8	86.8	3.3	1.9	2.0
Cycledata Corp.	1.9 L	5.0 L	2.3	2.0 L	1.9 L	2.1 L	2.3 L	2.5	2.8	3.0	3.3	4.2	5.0	4.0	4.7	87.0	2.9	2.2	2.1
June Consensus	**2.2**	**5.2**	**2.6**	**2.3**	**2.2**	**2.4**	**2.6**	**2.8**	**3.0**	**3.2**	**3.4**	**4.4**	**5.2**	**4.0**	**4.8**	**87.3**	**2.8**	**2.1**	**2.1**
Top 10 Avg.	2.3	5.4	2.7	2.4	2.4	2.5	2.7	2.9	3.2	3.4	3.7	4.7	5.5	4.3	5.0	89.6	3.2	2.5	2.7
Bottom 10 Avg.	2.0	5.0	2.5	2.1	2.0	2.2	2.4	2.6	2.8	2.9	3.1	4.1	4.9	3.8	4.6	84.8	2.4	1.8	1.4
May Consensus	2.2	5.2	2.6	2.3	2.2	2.4	2.5	2.7	3.0	3.2	3.5	4.4	5.2	4.0	4.8	86.7	2.9	2.1	2.1
Number of Forecasts Changed From A Month Ago:																			
Down	4	5	5	7	7	6	4	4	4	6	11	6	5	8	7	5	9	9	10
Same	36	31	18	14	17	12	12	17	18	21	21	9	10	6	12	8	28	21	24
Up	3	2	11	5	15	17	19	23	21	17	10	11	12	7	16	14	7	12	10
Diffusion Index	49 %	46 %	59 %	46 %	60 %	66 %	71 %	72 %	70 %	63 %	49 %	60 %	63 %	48 %	63 %	67 %	48 %	54 %	50 %

First Quarter 2019

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For ---Qtr.--- A. Fed's Major Currency $ Index	(Q-Q % Change) (SAAR) B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Moody's Analytics	3.0 H	6.1 H	3.3 H	3.0 H	2.8 H	2.8	3.1 H	3.3 H	3.6	3.8 H	4.5 H	5.4 H	6.3 H	4.3	5.2	na	2.7	3.0 H	2.6
RBC Capital Markets	2.6	na	na	na	na	na	na	3.0	3.3	3.5	3.7	na	na	na	na	na	2.4	2.4	1.9
J.P. Morgan Chase	2.6	na	3.0	na	na	na	na	3.0	3.1	3.2	3.3	na	na	na	na	na	2.3	2.2	2.3
Barclays	2.6	5.8	na	na	na	na	na	2.7	2.7	2.8	3.0	na	na	na	na	na	2.5	2.1	1.8
BNP Paribas Americas	2.6	na	2.6	na	na	na	na	2.8	3.1	3.3	na	na	na	na	na	na	1.1 L	na	2.0
Nomura Securities, Inc.	2.5	5.5	na	na	na	na	na	3.0	3.1	3.3	na	4.3	4.8	na	na	na	2.4	2.0	2.3
Goldman Sachs & Co.	2.5	na	2.8	na	2.4	na	na	2.8	3.2	3.3	3.5	na	na	na	4.7	na	1.9	2.4	2.4
Scotiabank Group	2.5	5.5	na	na	2.6	na	na	2.8	3.0	3.1	3.3	na	na	na	na	na	2.4	2.5	2.4
Naroff Economic Advisors	2.5	5.5	2.8	2.6	2.6	2.9 H	3.0	3.1	3.3	3.5	3.9	5.0	5.8	4.7 H	5.3 H	83.2	3.2 H	2.4	2.5
Swiss Re	2.5	5.5	2.6	2.4	2.4	2.5	2.6	2.8	2.7	2.9	3.5	4.7	5.6	na	4.8	na	1.9	1.6 L	3.1
NatWest Markets	2.5	5.6	2.9	2.5	2.6	2.8	3.0	3.0	3.3	3.3	3.5	4.6	5.3	4.1	5.1	89.0	2.8	2.3	2.3
MacroFin Analytics	2.5	5.5	3.1	2.6	2.6	2.8	3.1 H	3.3 H	3.7 H	3.8	4.0	4.8	5.6	4.6	5.3 H	89.8	2.3	2.3	2.2
DePrince & Assoc.	2.5	5.5	2.8	2.6	2.5	2.7	2.8	3.1	3.3	3.4	3.6	4.6	5.7	4.4	5.1	89.7	2.8	2.2	2.4
Amherst Pierpont Securities	2.5	5.6	2.9	2.5	2.5	2.7	2.9	3.1	3.4	3.7	4.1	5.0	5.8	4.5	5.3 H	91.0	2.7	2.6	3.2 H
S&P Global	2.5	5.3	2.7	na	2.3	2.6	2.7	2.8	3.0	3.3	3.5	na	na	na	4.7	84.0	2.3	2.1	1.9
BMO Capital Markets	2.5	5.6	2.9	na	2.4	2.6	2.7	2.9	3.2	3.3	3.5	na	na	na	4.9	84.4	2.7	2.2	2.4
MUFG Union Bank	2.5	5.5	2.8	2.4	2.4	2.5	2.9	2.8	3.1	3.2	3.5	4.2	5.0	4.1	4.8	81.0 L	2.7	2.1	3.0
The Northern Trust Company	2.4	5.6	2.9	2.5	2.6	2.7	2.8	3.0	3.3	3.6	3.9	5.0	5.9	4.6	5.2	84.5	2.0	2.0	2.0
High Frequency Economics	2.4	5.5	na	na	2.5	2.6	2.8	2.9	3.1	3.3	3.5	na	na	na	na	na	2.6	2.7	2.7
Chmura Economics & Analytics	2.4	5.5	3.0	2.5	2.5	2.7	2.9	3.1	3.3	3.4	3.8	4.5	na	na	5.0	87.8	3.2	2.1	2.3
Oxford Economics	2.4	5.3	2.9	na	2.3	2.5	2.6	2.8	2.9	3.2	3.6	na	na	na	4.8	84.5	2.0	2.5	2.1
Chase Wealth Management	2.4	5.5	2.9	2.7	2.5	2.7	2.8	2.9	3.1	3.3	3.6	4.4	5.2	4.2	4.9	89.0	1.7	2.1	2.2
RDQ Economics	2.4	5.5	2.8	2.5	2.6	2.8	2.9	2.9	3.2	3.4	3.6	4.9	5.5	4.3	5.0	90.6	2.3	2.3	2.3
Daiwa Capital Markets America	2.4	5.5	2.9	2.6	2.5	2.6	2.8	3.1	3.4	3.5	3.8	4.6	5.4	na	5.2	89.0	2.5	2.3	2.4
Wells Fargo	2.4	5.4	2.7	2.3	2.6	2.7	2.7	3.0	3.2	3.4	3.5	4.5	5.3	4.0	4.9	85.5	2.2	2.3	2.6
Bank of America Merrill Lynch	2.4	na	2.9	na	2.5	na	na	2.9	3.2	3.3	3.4	na	na	na	na	na	1.9	1.8	1.9
Regions Financial Corporation	2.3	5.4	2.8	2.3	2.3	2.5	2.6	2.8	3.2	3.3	3.6	4.6	5.3	4.3	4.9	88.0	2.4	2.1	2.0
Via Nova Investment Mgt.	2.3	5.3	2.8	2.2	2.2	2.4	2.6	2.8	3.3	3.6	3.8	4.7	5.2	4.7 H	5.2	88.0	2.8	2.2	2.3
GLC Financial Economics	2.3	5.3	2.7	2.4	2.4	2.5	2.7	2.9	3.3	3.5	3.6	4.8	5.5	4.2	5.1	86.6	2.4	2.1	2.2
Grant Thornton/Diane Swonk	2.3	5.3	2.8	2.6	2.3	2.7	2.9	3.1	3.3	3.4	3.7	4.0 L	5.2	3.6	5.0	91.7 H	2.7	2.5	0.9
ACIMA Private Wealth	2.3	5.3	2.7	2.6	2.2	2.3	2.2 L	2.3 L	2.2 L	2.2 L	2.7 L	4.0 L	5.0	3.8	4.3 L	83.5	1.9	2.1	1.3
AIG	2.3	5.3	na	na	2.1	2.5	2.8	2.8	3.1	3.3	3.7	na	5.1	na	4.8	na	2.6	2.3	1.3
Loomis, Sayles & Company	2.3	5.4	2.8	2.4	2.3	2.5	2.6	2.6	2.9	3.2	3.4	4.2	4.9	3.9	4.7	87.3	3.1	2.6	2.2
Societe Generale	2.2	5.5	na	na	2.5	na	na	3.0	na	3.0	3.1	na	na	na	na	na	1.7	1.9	1.8
Action Economics	2.2	5.3	2.5	2.3	2.3	2.4	2.6	2.8	3.0	3.2	3.4	4.3	5.1	3.8	4.8	87.2	2.5	1.9	2.6
Economist Intelligence Unit	2.2	5.2 L	2.3 L	2.3	2.4	2.4	2.6	3.0	3.3	3.4	3.6	na	na	na	5.0	na	1.6	na	2.3
Nat'l Assn. of Realtors	2.2	5.2 L	na	2.2	2.3	2.4	2.6	2.8	3.1	3.3	3.5	4.4	5.2	na	4.8	na	2.7	2.3	3.1
Fannie Mae	2.2	5.3	na	na	2.6	2.7	2.7	2.9	3.1	3.1	3.2	na	na	na	4.8	na	2.9	2.5	0.7 L
Georgia State University	2.2	5.3	na	na	2.1	2.5	2.7	3.0	3.4	3.7	4.0	4.8	5.6	na	5.2	na	2.2	2.2	1.4
Moody's Capital Markets Group	2.2	5.3	2.8	2.4	2.2	2.4	2.5	2.5	2.7	2.9	3.0	4.0 L	4.7 L	3.5 L	4.6	89.7	2.1	1.9	1.8
Comerica Bank	2.2	5.3	2.6	na	2.1	2.3	2.5	2.7	3.0	3.2	3.4	na	na	na	4.8	na	2.6	2.0	2.3
PNC Financial Services Corp.	2.2	5.3	2.8	na	2.4	2.5	2.7	2.9	3.2	3.3	3.7	na	5.3	4.2	4.9	86.7	3.0	2.0	2.2
Stone Harbor Investment Partners	2.1	5.3	2.5	2.3	2.0 L	2.2 L	2.3	2.7	3.1	3.5	3.7	4.7	5.5	na	5.1	83.0	2.6	2.6	2.4
Cycledata Corp.	2.1 L	5.2 L	2.5	2.0 L	2.1	2.3	2.5	2.7	3.0	3.2	3.4	4.3	5.1	4.1	4.8	87.0	2.7	2.2	2.1
June Consensus	**2.4**	**5.4**	**2.8**	**2.5**	**2.4**	**2.6**	**2.7**	**2.9**	**3.1**	**3.3**	**3.5**	**4.6**	**5.3**	**4.2**	**4.9**	**87.0**	**2.4**	**2.2**	**2.2**
Top 10 Avg.	2.6	5.6	3.0	2.6	2.6	2.8	2.9	3.1	3.4	3.6	3.9	4.9	5.7	4.5	5.2	89.8	2.9	2.6	2.8
Bottom 10 Avg.	2.2	5.3	2.6	2.3	2.2	2.3	2.5	2.6	2.8	2.9	3.2	4.2	5.0	3.9	4.7	84.0	1.8	1.9	1.5
May Consensus	2.4	5.4	2.8	2.5	2.4	2.6	2.7	2.9	3.1	3.3	3.6	4.6	5.3	4.1	4.9	86.7	2.5	2.2	2.2
Number of Forecasts Changed From A Month Ago:																			
Down	4	5	4	5	6	9	6	6	6	6	14	10	4	7	8	5	9	11	14
Same	34	28	21	15	20	10	13	22	22	24	21	11	16	7	14	8	30	23	22
Up	6	6	9	6	13	16	16	16	15	14	7	6	8	6	13	13	5	8	8
Diffusion Index	52 %	51 %	57 %	52 %	59 %	60 %	64 %	61 %	60 %	59 %	42 %	43 %	57 %	48 %	57 %	65 %	45 %	46 %	43 %

Second Quarter 2019

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For ---Qtr.--- A. Fed's Major Currency $ Index	(Q-Q % Change) (SAAR) B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Moody's Analytics	3.4 H	6.5 H	3.7 H	3.4	3.1 H	3.2 H	3.4 H	3.5 H	3.7	3.9	4.6 H	5.5 H	6.4 H	4.3	5.3	na	2.3	2.9 H	2.7
J.P. Morgan Chase	2.9	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.0	2.2	2.3
RBC Capital Markets	2.9	na	na	na	na	na	na	3.3	3.5	3.6	3.8	na	na	na	na	na	3.4 H	2.2	2.4
Barclays Capital	2.9	6.0	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.5	2.1	1.8
Goldman Sachs & Co.	2.8	na	3.1	na	2.7	na	na	3.0	3.3	3.4	3.5	na	na	na	4.8	na	1.9	2.2	2.2
NatWest Markets	2.7	5.8	3.1	2.8	2.8	3.0	3.2	3.2	3.3	3.3	3.5	4.7	5.4	4.1	5.2	88.0	2.7	1.7 L	0.7
Naroff Economic Advisors	2.7	5.8	3.0	3.7 H	2.9	3.1	3.3	3.3	3.5	3.7	4.1	5.2	5.9	4.9 H	5.5 H	82.0 L	2.6	2.5	2.7
BMO Capital Markets	2.7	5.8	3.0	na	2.6	2.7	2.8	3.0	3.3	3.4	3.5	na	na	na	5.0	83.9	2.2	1.8	1.8
S&P Global	2.7	5.5	3.0	na	2.6	2.9	2.9	3.0	3.1	3.3	3.6	na	na	na	4.9	83.9	2.0	2.1	2.0
Amherst Pierpont Securities	2.7	5.8	3.2	2.8	2.8	2.9	3.1	3.3	3.6	3.9	4.3	5.2	6.1	4.7	5.5	91.5	2.8	2.5	3.3 H
MacroFin Analytics	2.7	5.8	3.3	2.8	2.9	3.0	3.3	3.5 H	3.9 H	4.0 H	4.2	5.0	5.9	4.8	5.5 H	90.2	2.6	2.3	2.2
RDQ Economics	2.7	5.8	3.1	2.8	2.8	3.0	3.1	3.1	3.4	3.6	3.8	5.2	5.8	4.6	5.3	90.8	2.2	2.3	2.3
DePrince & Associates	2.7	5.7	3.2	2.9	2.8	2.9	3.1	3.3	3.4	3.5	3.7	4.8	5.8	4.5	5.2	89.9	2.7	2.3	2.4
Daiwa Capital Markets America	2.7	5.8	3.2	2.9	2.8	2.9	3.1	3.4	3.6	3.7	3.9	4.8	5.6	na	5.4	90.0	2.4	2.3	2.4
MUFG Union Bank	2.7	5.8	3.0	2.7	2.7	2.8	3.2	3.0	3.2	3.3	3.5	4.3	5.1	4.2	4.9	82.0 L	2.9	2.1	3.0
High Frequency Economics	2.7	5.8	na	na	2.7	2.9	3.0	3.0	3.2	3.4	3.6	na	na	na	na	na	2.5	2.7	2.7
Chmura Economics & Analytics	2.7	5.8	3.3	2.8	2.7	2.9	3.1	3.3	3.5	3.6	3.9	4.7	na	na	5.1	86.8	3.3	1.9	2.3
Oxford Economics	2.7	5.5	3.1	na	2.6	2.8	2.8	3.0	3.1	3.3	3.6	na	na	na	5.0	84.7	2.2	2.3	2.1
Swiss Re	2.6	5.6	2.8	2.6	2.5	2.6	2.7	2.9	2.8	2.9	3.6	4.7	5.6	na	4.8	na	1.8	1.8	0.5 L
The Northern Trust Company	2.6	5.8	3.1	2.7	2.8	2.9	3.0	3.2	3.5	3.8	4.0	5.3 `	6.1	4.8	5.4	84.7	2.3	2.0	2.0
Bank of America Merrill Lynch	2.6	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.9	1.9	2.2
BNP Paribas Americas	2.6	na	2.7	na	na	na	na	2.8	3.1	3.3	na	na	na	na	na	na	2.0	na	1.5
Chase Wealth Management	2.6	5.8	3.0	3.0	2.7	2.9	3.0	3.1	3.3	3.5	3.8	4.6	5.4	4.4	5.1	88.8	2.3	2.0	2.3
Regions Financial Corporation	2.5	5.6	2.8	2.4	2.4	2.6	2.7	2.9	3.3	3.4	3.7	4.7	5.4	4.5	5.0	87.7	2.2	2.0	2.1
Grant Thornton/Diane Swonk	2.5	5.5	3.0	2.8	2.4	2.8	3.0	3.2	3.4	3.5	3.8	4.2	5.3	3.6	5.1	92.7 H	2.5	2.5	2.2
Nomura Securities, Inc.	2.5	5.5	na	na	na	na	na	3.0	3.0	3.1	na	4.2	4.7 L	na	na	na	2.1	2.0	1.4
AIG	2.5	5.6	na	na	2.4	2.7	2.9	2.9	3.1	3.3	3.7	na	5.1	na	4.8	na	2.3	2.5	1.5
Societe Generale	2.5	5.8	na	na	2.6	na	na	3.1	na	2.8	2.9	na	na	na	na	na	1.1 L	1.8	2.0
Via Nova Investment Mgt.	2.5	5.5	3.0	2.4	2.4	2.6	2.8	3.0	3.5	3.8	4.0	4.9	5.4	4.9 H	5.4	88.0	2.5	2.2	2.3
Economist Intelligence Unit	2.5	5.5	2.6	2.6	2.6	2.7	2.8	3.2	3.4	3.6	3.8	na	na	na	5.2	na	3.2	na	2.3
Wells Fargo	2.5	5.5	2.8	2.4	2.7	2.8	2.8	3.1	3.3	3.5	3.6	4.6	5.4	4.1	5.0	84.3	2.9	2.3	2.4
Scotiabank Group	2.5	5.5	na	na	2.6	na	na	3.0	3.0	3.1	3.3	na	na	na	na	na	2.3	2.5	2.4
Nat'l Assn. of Realtors	2.5	5.5	na	2.6	2.7	2.8	2.9	3.1	3.3	3.5	3.7	4.6	5.4	na	5.0	na	2.7	2.2	3.0
GLC Financial Economics	2.5	5.5	2.8	2.5	2.5	2.7	2.7	2.9	3.4	3.7	3.8	5.1	5.8	4.4	5.4	86.8	3.2	1.8	2.4
Action Economics	2.5	5.6	2.6	2.6	2.6	2.7	2.8	2.9	3.1	3.3	3.4	4.3	5.1	3.8	4.9	87.0	3.2	2.6	2.5
Georgia State University	2.4	5.5	na	na	2.3	2.7	2.8	3.1	3.5	3.8	4.2	5.0	5.9	na	5.3	na	2.1	2.3	2.0
Comerica Bank	2.4	5.5	2.8	na	2.3	2.5	2.7	2.9	3.2	3.3	3.6	na	na	na	5.0	na	2.5	2.0	2.1
PNC Financial Services Corp.	2.4	5.5	2.9	na	2.5	2.7	2.8	3.0	3.3	3.4	3.7	na	5.4	4.2	5.0	86.7	2.6	2.1	2.2
Loomis, Sayles & Company	2.4	5.5	2.9	2.5	2.4	2.5	2.6	2.8	3.0	3.3	3.5	4.3	5.0	4.0	4.8	87.4	2.7	2.4	2.2
Moody's Capital Markets Group	2.4	5.5	3.1	2.5	2.4	2.5	2.5	2.5	2.7	2.9	3.0	4.0	4.7 L	3.5 L	4.6	89.8	2.2	1.9	1.6
Fannie Mae	2.4	5.5	na	na	2.7	2.7	2.8	2.9	3.1	3.2	3.3	na	na	na	4.8	na	2.3	2.8	2.3
Stone Harbor Investment Partners	2.4	5.5	2.7	2.5	2.2	2.4	2.5	2.9	3.3	3.6	3.8	4.8	5.6	na	5.2	85.0	2.5	2.9	2.7
Cycledata Corp.	2.1	5.2	2.5 L	2.0 L	2.1	2.3	2.5	2.7	3.0	3.2	3.4	4.3	5.1	4.1	4.8	87.0	2.6	2.2	2.1
ACIMA Private Wealth	2.0 L	5.0 L	2.5 L	2.5	1.8 L	2.0 L	1.9 L	2.0 L	2.0 L	2.0 L	2.6 L	3.9 L	5.0	3.7	4.2 L	83.0	1.8	2.2	2.1
June Consensus	**2.6**	**5.6**	**3.0**	**2.7**	**2.6**	**2.7**	**2.9**	**3.0**	**3.2**	**3.4**	**3.7**	**4.7**	**5.5**	**4.3**	**5.1**	**87.0**	**2.4**	**2.2**	**2.2**
Top 10 Avg.	2.8	5.9	3.2	3.0	2.8	3.0	3.2	3.3	3.6	3.8	4.1	5.1	5.9	4.6	5.4	90.0	3.0	2.6	2.7
Bottom 10 Avg.	2.3	5.4	2.7	2.4	2.3	2.5	2.6	2.7	2.9	3.0	3.2	4.2	5.0	3.9	4.7	84.0	1.9	1.9	1.5
May Consensus	2.6	5.6	2.9	2.7	2.6	2.7	2.9	3.0	3.2	3.4	3.7	4.7	5.4	4.3	5.0	86.5	2.4	2.2	2.2
Number of Forecasts Changed From A Month Ago:																			
Down	4	4	5	5	6	8	8	6	5	6	12	8	7	6	8	5	10	8	7
Same	35	31	20	17	20	14	15	21	15	21	18	9	9	11	10	9	23	27	31
Up	5	4	7	4	12	13	12	14	20	14	9	10	12	6	17	11	11	7	6
Diffusion Index	51 %	50 %	53 %	48 %	58 %	57 %	56 %	60 %	69 %	60 %	46 %	54 %	59 %	50 %	63 %	62 %	51 %	49 %	49 %

Third Quarter 2019

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Moody's Analytics	3.7 H	6.9 H	4.0 H	3.7	3.4 H	3.5 H	3.7 H	3.8 H	3.9	4.0	4.7 H	5.5 H	6.5 H	4.4	5.4	na	1.9	2.8	2.6
J.P. Morgan Chase	3.1	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.8	2.3	2.4
RBC Capital Markets	3.1	na	na	na	na	na	na	3.5	3.6	3.7	3.8	na	na	na	na	na	3.4	1.4 L	3.0
Barclays Capital	3.1	6.3	na	na	na	na	na	na	na	na	na	na	na	na	na	na	2.0	2.3	2.2
Goldman Sachs & Co.	3.0	na	3.3	na	2.9	na	na	3.2	3.4	3.5	3.6	na	na	na	4.9	na	1.7	2.0	2.0
MUFG Union Bank	3.0	6.0	3.2	2.9	3.0	3.1	3.4	3.2	3.3	3.4	3.6	4.4	5.2	4.3	5.0	81.0 L	2.8	2.1	2.8
Amherst Pierpont Securities	3.0	6.1	3.4	3.0	3.0	3.2	3.3	3.4	3.8	4.0	4.4	5.3	6.2	4.8	5.7	92.0	2.6	2.6	3.3
High Frequency Economics	2.9	6.0	na	na	3.0	3.1	3.2	3.1	3.3	3.5	3.7	na	na	na	na	na	2.1	2.8	2.8
Chmura Economics & Analytics	2.9	6.0	3.5	3.1	3.0	3.2	3.3	3.5	3.7	3.7	4.1	4.8	na	na	5.2	86.2	3.7 H	2.2	2.4
Oxford Economics	2.9	5.7	3.2	na	2.8	3.0	3.0	3.1	3.2	3.3	3.7	na	na	na	5.1	84.9	1.9	2.5	2.0
Naroff Economic Advisors	2.9	6.0	3.2	4.0 H	3.2	3.3	3.4	3.6	3.7	4.0	4.3	5.5 H	6.1	5.0	5.7 H	83.5	2.2	2.3	2.3
RDQ Economics	2.9	6.0	3.3	3.0	3.0	3.1	3.2	3.3	3.6	3.8	4.0	5.5 H	6.1	4.9	5.5	91.3	2.3	2.4	2.4
Daiwa Capital Markets America	2.9	6.0	3.3	3.1	3.0	3.1	3.3	3.5	3.7	3.8	4.0	4.9	5.7	na	5.6	90.0	2.2	2.4	2.5
MacroFin Analytics	2.9	6.0	3.5	3.0	3.1	3.2	3.5	3.7	4.1 H	4.2 H	4.4	5.2	6.0	5.0	5.7 H	90.5	2.3	2.1	2.1
NatWest Markets	2.9	6.0	3.2	2.9	2.9	3.1	3.2	3.3	3.3	3.4	3.6	4.8	5.5	4.1	5.2	88.0	2.6	2.0	1.3 L
S&P Global	2.9	5.6	3.1	na	2.7	2.9	3.0	3.0	3.2	3.4	3.7	na	na	na	5.0	83.7	2.3	2.1	1.9
BMO Capital Markets	2.9	6.0	3.1	na	2.6	2.8	2.9	3.1	3.3	3.4	3.6	na	na	na	5.1	83.5	2.0	1.9	2.0
Bank of America Merrill Lynch	2.9	na	na	na	na	na	na	na	na	na	na	na	na	na	na	na	1.9	1.9	2.4
Swiss Re	2.9	5.9	3.0	2.8	2.7	2.9	3.0	3.1	2.9	3.0	3.7	4.7	5.6	na	4.8	na	1.7	3.4 H	3.4 H
DePrince & Associates	2.9	5.9	3.3	3.1	3.0	3.1	3.2	3.4	3.5	3.6	3.8	5.1	5.9	4.7	5.4	90.1	2.7	2.2	2.4
Chase Wealth Management	2.8	6.0	3.2	3.2	2.9	3.1	3.2	3.3	3.5	3.7	4.0	4.8	5.6	4.6	5.3	88.7	2.1	2.1	2.2
Via Nova Investment Mgt.	2.8	5.8	3.2	2.7	2.7	2.8	3.1	3.3	3.8	4.0	4.3	5.2	5.6	5.2 H	5.6	88.0	2.4	2.2	2.3
Nomura Securities, Inc.	2.8	5.8	na	na	na	na	na	3.0	3.0	3.0	na	4.0	4.6	na	na	na	2.1	2.0	2.5
Action Economics	2.7	5.8	2.9	2.8	2.9	2.9	3.0	3.1	3.2	3.3	3.4	4.3	5.1	3.8	4.9	86.8	3.1	2.3	2.5
Societe Generale	2.7	5.8	na	na	2.7	na	na	3.0	na	2.5	2.9	na	na	na	na	na	0.0 L	1.7	1.7
Wells Fargo	2.7	5.7	2.9	2.6	2.8	2.9	2.9	3.2	3.3	3.6	3.7	4.6	5.5	4.2	5.1	82.8	2.7	2.4	2.9
The Northern Trust Company	2.7	5.8	3.1	2.8	2.8	2.9	3.0	3.2	3.6	3.9	4.2	5.4	6.2	4.9	5.5	84.9	1.9	2.0	2.0
Economist Intelligence Unit	2.7	5.7	2.7	2.8	2.8	2.8	3.0	3.3	3.6	3.7	4.0	na	na	na	5.3	na	2.2	na	2.3
Grant Thornton/Diane Swonk	2.7	5.7	3.2	3.0	2.5	2.9	3.1	3.3	3.4	3.6	4.0	4.3	5.4	3.7	5.1	93.1 H	2.3	2.6	2.4
AIG	2.7	5.7	na	na	2.5	2.8	3.0	3.0	3.1	3.4	3.8	na	5.3	na	4.9	na	2.2	2.5	1.5
Comerica Bank	2.7	5.8	3.1	na	2.6	2.7	2.9	3.1	3.4	3.5	3.8	na	na	na	5.2	na	2.4	2.0	2.0
Georgia State University	2.6	5.8	na	na	2.4	2.9	3.0	3.3	3.6	3.9	4.3	5.2	6.0	na	5.4	na	2.2	2.2	2.0
Loomis, Sayles & Company	2.6	5.7	3.1	2.7	2.6	2.7	2.7	2.8	3.0	3.3	3.5	4.3	5.0	4.0	4.8	87.5	2.6	2.4	2.2
Stone Harbor Investment Partners	2.6	5.8	3.0	2.8	2.5	2.6	2.8	3.1	3.4	3.7	3.8	4.9	5.7	na	5.3	86.0	2.3	3.0	3.0
BNP Paribas Americas	2.6	na	2.7	na	na	na	na	2.7	3.0	3.2	na	na	na	na	na	na	1.2	na	2.4
Nat'l Assn. of Realtors	2.6	5.6	na	2.7	2.8	2.9	3.0	3.2	3.4	3.6	3.8	4.7	5.6	na	5.1	na	2.6	2.1	2.8
Regions Financial Corporation	2.6	5.6	2.9	2.5	2.5	2.6	2.7	2.9	3.3	3.4	3.8	4.7	5.5	4.5	5.0	87.3	1.9	2.1	2.1
GLC Financial Economics	2.6	5.6	2.8	2.6	2.6	2.7	2.7	2.9	3.5	3.8	4.0	5.4	6.1	4.6	5.5	86.9	2.6	2.1	2.5
PNC Financial Services Corp.	2.5	5.5	3.0	na	2.7	2.8	2.9	3.0	3.3	3.4	3.7	na	5.4	4.1	5.0	86.7	2.3	2.1	2.2
Scotiabank Group	2.5	5.5	na	na	2.6	na	na	3.0	3.1	3.2	3.4	na	na	na	na	na	2.2	2.0	2.5
Moody's Capital Markets Group	2.4	5.5	3.1	2.5	2.4	2.4	2.4	2.4	2.6	2.8	2.9	4.1	4.6 L	3.4 L	4.5	89.6	2.1	2.0	1.8
Fannie Mae	2.4	5.5	na	na	2.8	2.8	2.9	3.0	3.1	3.2	3.3	na	na	na	4.8	na	2.2	2.5	2.9
Cycledata Corp.	2.1	5.2	2.5 L	2.0 L	2.1	2.3	2.5	2.7	3.0	3.2	3.4	4.3	5.1	4.1	4.8	87.0	2.6	2.2	2.1
ACIMA Private Wealth	1.9 L	4.9 L	2.5 L	2.5	1.7 L	1.9 L	1.9 L	2.0 L	2.0 L	1.9 L	2.5 L	3.9 L	5.0	3.7	3.3 L	84.0	1.8	2.0	1.9
June Consensus	**2.8**	**5.8**	**3.1**	**2.9**	**2.7**	**2.9**	**3.0**	**3.1**	**3.3**	**3.5**	**3.8**	**4.8**	**5.6**	**4.4**	**5.1**	**87.1**	**2.2**	**2.2**	**2.3**
Top 10 Avg.	3.1	6.1	3.4	3.2	3.0	3.2	3.4	3.5	3.7	3.9	4.2	5.3	6.1	4.8	5.6	90.1	2.9	2.7	3.0
Bottom 10 Avg.	2.4	5.4	2.8	2.5	2.4	2.5	2.6	2.7	2.9	2.9	3.2	4.3	5.1	3.9	4.7	84.0	1.6	1.9	1.8
May Consensus	2.8	5.8	3.1	2.9	2.7	2.9	3.0	3.1	3.3	3.5	3.8	4.8	5.5	4.4	5.1	86.6	2.2	2.3	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	4	4	6	5	7	8	7	7	5	8	13	9	4	5	7	6	11	11	9
Same	35	29	18	16	19	14	14	18	18	23	18	13	13	8	14	10	22	25	28
Up	5	6	8	5	12	13	14	16	17	10	8	5	11	8	14	10	11	6	7
Diffusion Index	51 %	53 %	53 %	50 %	57 %	57 %	60 %	61 %	65 %	52 %	44 %	43 %	63 %	57 %	60 %	58 %	50 %	44 %	48 %

International Interest Rate And Foreign Exchange Rate Forecasts

United States

	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			Fed's Major Currency $ Index		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	2.75	2.75	na	na	na	na
BMO Capital Markets	na	na	na	3.16	3.23	3.39	86.7	85.2	83.9
IHSMarkit	na	na	na	3.19	3.32	3.51	na	na	na
ING Financial Markets	2.65	2.85	3.05	3.40	3.30	3.20	94.4	96.9	97.2
Mizuho Research Institute	2.35	2.35	2.35	3.20	3.20	3.20	87.0	86.0	86.0
Moody's Analytics	na	na	na	3.29	3.60	3.89	na	na	na
Moody's Capital Markets	na	na	na	3.00	2.93	2.88	88.0	88.5	89.0
Nomura Securities	na	na	na	na	na	na	na	na	na
Oxford Economics	na	na	na	3.14	3.20	3.00	86.8	85.1	84.7
Scotiabank	na	na	na	2.97	3.03	3.30	na	na	na
Wells Fargo	2.50	2.65	2.90	3.05	3.20	3.37	na	na	na
June Consensus	**2.50**	**2.62**	**2.77**	**3.12**	**3.18**	**3.30**	**88.6**	**88.3**	**88.2**
High	2.65	2.85	3.05	3.40	3.60	3.89	94.4	96.9	97.2
Low	2.35	2.35	2.35	2.75	2.75	2.88	86.7	85.1	83.9
Last Months Avg.	2.09	2.21	2.36	3.01	3.13	3.27	87.5	87.5	87.3

Japan

	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/YEN		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	0.05	0.05	na	103.0	101.0	na
BMO Capital Markets	na	na	na	0.07	0.09	0.11	108.0	106.0	104.0
IHSMarkit	na	na	na	na	na	na	109.4	109.9	112.2
ING Financial Markets	0.05	0.05	0.10	0.10	0.10	0.10	105.0	105.0	102.0
Mizuho Research Institute	0.09	0.09	0.09	0.05	0.05	0.05	110.0	108.0	108.0
Moody's Analytics	na	na	na	0.06	0.06	0.04	110.8	111.9	111.1
Moody's Capital Markets	na	na	na	0.05	0.08	0.13	112.0	113.0	114.0
Nomura Securities	na	na	na	na	na	na	108.0	110.0	110.0
Oxford Economics	na	na	na	0.08	0.08	0.08	109.5	110.6	113.4
Scotiabank	na	na	na	na	na	na	109.0	110.0	110.0
Wells Fargo	-0.02	-0.01	0.00	0.07	0.08	0.10	na	na	na
June Consensus	**0.04**	**0.04**	**0.06**	**0.07**	**0.07**	**0.09**	**108.5**	**108.5**	**109.4**
High	0.09	0.09	0.10	0.10	0.10	0.13	112.0	113.0	114.0
Low	-0.02	-0.01	0.00	0.05	0.05	0.04	103.0	101.0	102.0
Last Months Avg.	0.02	0.02	0.03	0.06	0.07	0.08	107.5	107.9	108.8

United Kingdom

	3 Mo. Interest Rate %			10 Yr. Gilt Yields %			GBP/USD		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	1.70	1.75	na	1.42	1.44	na
BMO Capital Markets	na	na	na	1.72	1.93	2.21	1.39	1.42	1.45
IHSMarkit	na	na	na	na	na	na	1.39	1.38	1.39
ING Financial Markets	0.80	0.80	1.05	1.75	1.85	1.90	1.40	1.53	1.61
Mizuho Research Institute	0.85	0.85	1.10	1.60	1.65	1.80	na	na	na
Moody's Analytics	na	na	na	1.70	1.69	1.91	1.33	1.28	1.29
Moody's Capital Markets	na	na	na	1.50	1.55	1.60	1.33	1.32	1.31
Nomura Securities	na	na	na	na	na	na	1.43	1.48	1.48
Oxford Economics	na	na	na	1.94	2.20	2.45	1.42	1.47	1.48
Scotiabank	na	na	na	na	na	na	1.41	1.45	1.48
Wells Fargo	0.80	0.90	1.15	1.70	1.85	2.10	na	na	na
June Consensus	**0.82**	**0.85**	**1.10**	**1.70**	**1.81**	**2.00**	**1.39**	**1.42**	**1.44**
High	0.85	0.90	1.15	1.94	2.20	2.45	1.43	1.53	1.61
Low	0.80	0.80	1.05	1.50	1.55	1.60	1.33	1.28	1.29
Last Months Avg.	0.83	0.83	0.96	1.64	1.75	1.98	1.40	1.41	1.45

Switzerland

	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/CHF		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	na	na	na	0.97	0.97	na
BMO Capital Markets	na	na	na	na	na	na	0.98	0.97	0.97
IHSMarkit	na	na	na	na	na	na	1.00	1.00	1.01
ING Financial Markets	-0.65	-0.65	-0.65	0.20	0.25	0.45	1.00	0.96	0.96
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Moody's Analytics	na	na	na	0.24	0.30	0.46	1.00	1.04	1.04
Moody's Capital Markets	na	na	na	0.05	0.08	0.10	1.00	1.00	1.00
Nomura Securities	na	na	na	na	na	na	0.98	0.94	0.94
Oxford Economics	na	na	na	0.23	0.34	0.64	0.94	0.91	0.91
Scotiabank	na	na	na	na	na	na	na	na	na
Wells Fargo	na	na	na	na	na	na	na	na	na
June Consensus	**-0.65**	**-0.65**	**-0.65**	**0.18**	**0.24**	**0.41**	**0.98**	**0.97**	**0.98**
High	-0.65	-0.65	-0.65	0.24	0.34	0.64	1.00	1.04	1.04
Low	-0.65	-0.65	-0.65	0.05	0.08	0.10	0.94	0.91	0.91
Last Months Avg.	-0.75	-0.75	-0.75	0.14	0.23	0.40	0.97	0.97	0.96

Canada

	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/CAD		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	na	na	na	1.29	1.28	na
BMO Capital Markets	na	na	na	2.60	2.70	2.97	1.27	1.26	1.24
IHSMarkit	na	na	na	na	na	na	1.24	1.23	1.27
ING Financial Markets	2.00	2.00	2.30	2.60	2.70	2.90	1.25	1.23	1.20
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Moody's Analytics	na	na	na	3.10	3.53	3.91	1.27	1.26	1.23
Moody's Capital Markets	na	na	na	2.48	2.45	2.40	1.29	1.29	1.29
Nomura Securities	na	na	na	na	na	na	1.30	1.28	1.26
Oxford Economics	na	na	na	2.67	2.79	3.04	1.28	1.28	1.27
Scotiabank	na	na	na	2.48	2.53	2.63	1.26	1.25	1.23
Wells Fargo	1.90	2.00	2.25	2.50	2.50	2.65	na	na	na
June Consensus	**1.95**	**2.00**	**2.28**	**2.63**	**2.74**	**2.93**	**1.27**	**1.26**	**1.25**
High	2.00	2.00	2.30	3.10	3.53	3.91	1.30	1.29	1.29
Low	1.90	2.00	2.25	2.48	2.45	2.40	1.24	1.23	1.20
Last Months Avg.	1.78	1.95	2.08	2.49	2.68	2.87	1.27	1.26	1.24

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			AUD/AUD		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	na	na	na	0.77	0.77	na
BMO Capital Markets	na	na	na	na	na	na	0.77	0.78	0.79
IHSMarkit	na	na	na	na	na	na	0.73	0.73	0.72
ING Financial Markets	1.90	2.05	2.40	3.00	3.20	3.30	0.78	0.80	0.85
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Moody's Analytics	na	na	na	2.67	2.67	2.74	0.76	0.74	0.72
Moody's Capital Markets	na	na	na	2.90	2.93	2.90	0.76	0.75	0.75
Nomura Securities	na	na	na	na	na	na	0.73	0.75	0.77
Oxford Economics	na	na	na	3.00	3.14	3.27	0.76	0.76	0.76
Scotiabank	na	na	na	na	na	na	0.79	0.80	0.81
Wells Fargo	na	na	na	na	na	na	na	na	na
June Consensus	**1.90**	**2.05**	**2.40**	**2.89**	**2.98**	**3.05**	**0.76**	**0.76**	**0.77**
High	1.90	2.05	2.40	3.00	3.20	3.30	0.79	0.80	0.85
Low	1.90	2.05	2.40	2.67	2.67	2.74	0.73	0.73	0.72
Last Months Avg.	1.80	1.90	2.20	2.83	2.93	3.06	0.76	0.77	0.78

Eurozone

	3 Mo. Interest Rate %			USD/EUR		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	na	na	na	1.22	1.22	na
BMO Capital Markets	na	na	na	1.22	1.24	1.26
IHSMarkit	na	na	na	1.20	1.20	1.19
ING Financial Markets	-0.33	-0.33	-0.20	1.23	1.30	1.32
Mizuho Research Institute	-0.30	-0.30	-0.20	1.22	1.24	1.25
Moody's Analytics	na	na	na	1.18	1.14	1.13
Moody's Capital Markets	na	na	na	1.17	1.17	1.17
Nomura Securities	na	na	na	1.23	1.27	1.30
Oxford Economics	na	na	na	1.25	1.30	1.30
Scotiabank	na	na	na	1.27	1.29	1.32
Wells Fargo	-0.30	-0.20	0.05	na	na	na
June Consensus	**-0.31**	**-0.28**	**-0.12**	**1.22**	**1.24**	**1.25**
High	-0.30	-0.20	0.05	1.27	1.30	1.32
Low	-0.33	-0.33	-0.20	1.17	1.14	1.13
Last Months Avg.	-0.33	-0.32	-0.23	1.23	1.23	1.26

10 Yr. Gov't Bond Yields %

	Germany			France			Italy			Spain		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Barclays	0.75	0.85	na	na	na	na	na	na	na	na	na	na
BMO Capital Markets	0.85	1.07	1.30	na	na	na	na	na	na	na	na	na
ING Financial Markets	0.70	0.75	0.90	1.00	1.05	1.20	2.20	2.15	2.30	1.50	1.55	1.70
Mizuho Research Institute	0.65	0.70	0.75	na	na	na	na	na	na	na	na	na
Moody's Analytics	0.72	0.93	1.22	0.97	1.07	1.25	2.02	2.19	2.37	1.82	2.03	2.25
Moody's Capital Markets	0.65	0.70	0.75	0.93	1.00	1.05	2.45	2.46	1.45	1.57	1.65	1.73
Nomura Securities	na	na	na	na	na	na	na	na	na	na	na	na
Oxford Economics	0.80	0.95	1.18	1.15	1.32	1.57	2.10	2.30	2.63	1.50	1.72	2.14
Wells Fargo	0.75	0.90	1.20	na	na	na	na	na	na	na	na	na
June Consensus	**0.73**	**0.86**	**1.04**	**1.01**	**1.11**	**1.27**	**2.19**	**2.27**	**2.19**	**1.60**	**1.74**	**1.96**
High	0.85	1.07	1.30	1.15	1.32	1.57	2.45	2.46	2.63	1.82	2.03	2.25
Low	0.65	0.70	0.75	0.93	1.00	1.05	2.02	2.15	1.45	1.50	1.55	1.70
Last Months Avg.	0.70	0.81	1.03	0.93	1.06	1.29	1.98	2.09	2.33	1.47	1.61	1.86

Consensus Forecasts 10-year Bond Yields vs U.S. Yield

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-2.98	-3.05	-3.10	-3.22
United Kingdom	-1.45	-1.41	-1.37	-1.31
Switzerland	-2.87	-2.94	-2.93	-2.89
Canada	-0.51	-0.48	-0.43	-0.38
Australia	-0.18	-0.22	-0.19	-0.25
Germany	-2.39	-2.38	-2.32	-2.26
France	-2.17	-2.10	-2.07	-2.04
Italy	-0.88	-0.92	-0.90	-1.12
Spain	-1.76	-1.52	-1.44	-1.35

Consensus Forecasts 3 Mo. Deposit Rates vs U.S. Rate

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-2.35	-2.46	-2.66	-2.70
United Kingdom	-1.68	-1.68	-1.77	-1.67
Switzerland	-3.04	-3.15	-3.27	-3.42
Canada	-0.62	-0.55	-0.62	-0.49
Australia	-0.29	-0.60	-0.57	-0.37
Eurozone	-2.65	-2.81	-2.89	-2.88

Viewpoints: A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

3:10 To Luna

To begin, let me apologize to the Oscar-nominated Western, 3:10 to Yuma, for title tainting. But, the sight of 10-year Treasury yields closing above 3.10% during this week—for the first time in nearly 7 years—was too tempting. The 3.10% mark happened to be our forecast for the average level this December, and we've hit it some seven months early. With a slight upward revision to our oil price projection as a backdrop, we're changing our year-end forecast to 3.25% (and lifting our Canada 10-year forecast to 2.70% from 2.55%)—a modest "moonward" adjustment (okay… I apologize for the cheesy "Luna" rhyme too). Importantly, we still expect longer-term yields to exhibit a ratcheting pattern, posting temporary rallies (perhaps even back below 3% in the weeks ahead) as yield-starved investors take advantage of the multiyear highs. This will continue to restrain the net rising trend, despite it having perked up in the past couple of weeks. Several factors have contributed to the perking.

First, the economy is picking up. The rote Q1 slowdown is behind us and left the economy no worse for wear. Indeed, real GDP growth actually accelerated to 2.9% y/y in Q1, up from 2.6% in Q4. And, the emerging stream of Q2 economic indicators has, so far, proved to be consistently upbeat. For example, the Atlanta Fed's GDP Nowcast began tracking Q2 three weeks ago. As was the case in the previous four quarterly trackings, the growth rate prediction first began at least at 4%. However, unlike these prior episodes, the reading has not receded but moved sideways, indicative of a consistent solid tone to the data flow.

Second, headline inflation risk is increasing, greased by higher oil prices. WTI crude has closed above $70 for the past eight days, the highest level in 3½ years. The factors fuelling this rise—the potential for reduced supply from Iran and Venezuela along with expectations for sturdy crude oil demand—led us to revise up our oil price forecast. We now see WTI closing above $65 this year versus closer to $60 before.

Third, some labour market metrics passed some key milestones, stoking wage growth expectations. The unemployment rate slipped below 4% in April (down two tenths to 3.9%), which, apart from a sole 3.8% print in April 2000, was the lowest jobless rate in more than 48 years. Also, the number of unemployed now sits below the number of job openings for the first time since the latter data commenced in 2000. Finally, the two-tenths drop in the broad U6 rate to 7.8% catapulted it to an exact 17-year low (it matched the lowest level in more than 11 years before).

Fourth, the pace of Fed redemptions is picking up, so there's increasingly less Fed demand being recycled into all maturities. In the four weeks ended May 16th, more than $26 billion was not rolled over, which is at least 75% above any other four-week period since balance sheet normalization commenced in October 2017. Meanwhile, Treasury is increasing its debt issuance across all maturities to finance the return of trillion-dollar deficits. Although this is skewed more to shorter-term maturities than longer-term tenors, a record amount of 10-year notes and 30-year bonds were still issued in May (the record dates to 1980).

On balance, while we don't expect yields to continue escalating at their present pace, a moderate net uptrend now seems to have a tighter grip on Treasuries.

Michael Gregory, BMO Capital Markets, Toronto Canada

Don't Fret About Household Debt (Yet)

It feels like every few months a major media outlet will splash a story about the return of the overleveraged US consumer. Every few months—three, to be precise—the NY Fed's quarterly report on household debt and credit arrives to provide a cross-check to these stories. Unlike many of the data sources in the news, the NY Fed report is a rigorously designed, nationally representative look at all forms of household credit. The latest such report, released Thursday and covering 1Q18—indicates there is little evidence that households are levering up, that credit quality is worsening, or that loan performance is deteriorating.

In fairness to the fourth estate, it doesn't hurt to remain vigilant, particularly in light of the aftermath of the early 2000s credit boom. While there is so far little sign of household credit becoming a problem, that could change fairly quickly and so a quarterly check-up is well-advised. And rather than continually fighting the last war we should also be vigilant to other areas of credit growth. Credit growth in the nonfinancial business sector, for example, may be exhibiting a little more froth than in the household sector.

Total household debt increased by $63 billion last quarter to $13.2 trillion, well above the $12.7 trillion peak reached at the end of the last cycle. Of course a lot of nominal variables are at all-time highs—GDP, consumption, income, etc.—and so a sense of proportion is warranted. Scaled by personal income, household debt stood at 78.2% of income in 1Q18, down slightly from 4Q17 and well off the 104.4% peak reached in 1Q09. In fact, since 4Q12 the debt-to-income ratio has hovered in a narrow 76%-80% range. Aggregates can mask demographic heterogeneity, but the separately-reported triennial Survey of Consumer Finances indicates that in 2016—the latest data point—leverage was below its peak for all income quintiles.

The performance of loans to the household sector continues to improve. Perhaps this should not be surprising given the decline in the jobless rate and steady growth in labor income. Households are now current on 95.4% of their loans; this is the highest level of the expansion.

One area of recurring focus for household loan performance is auto loans. Newly delinquent loan balances for autos stood at 7.3% of current balances in 1Q18.

Recent auto delinquencies are lower than they were during most of the last expansion, and obviously well off recession highs, though they are somewhat higher than the lows of the cycle. Those lows occurred after auto lenders tightened standards in the wake of the recession. As the recovery became more entrenched standards loosened modestly, with subsequent effects on performance. More recently, however, auto lenders have begun requiring cleaner credit, and the latest median credit score stood at 708, the highest since early 2011 (the bottom of the credit score distribution has risen in tandem). Given the recent tightening in standards, auto loan performance should remain reasonably healthy.

Auto loans represent less than 10% of household credit, while home mortgages are 67% of borrowing. It is harder to write a scary story about mortgage performance: newly delinquent mortgages stand at only 3.38% of current balances, the lowest in the history of a series going back 15 years. The low level of new or seriously delinquent loans is being felt down the pipeline, as the percent of consumers with new foreclosures remains at an all-time low of 0.03%.

The favorable news on mortgage loan performance has not encouraged mortgage lenders to loosen standards noticeably, so far. Median credit scores in 1Q18 stood at 761. While this is off the immediate post-recession highs, it remains 40 points higher than the pre-recession average.

Excessive and unaffordable debt can be a problem for the macroeconomy via two channels. First, for borrowers a a debt overhang can limit their ability to spend on other items. Second, for lenders non-performing loans can eat into capital thereby limiting the lenders' ability to extend credit to other borrowers. This second channel is not operative when it comes to student loans: the lender is increasingly the federal government. However, the first channel *(continued on next page)*

Viewpoints

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

could still be a concern, particularly if the economy heads to a nasty place. Recently there has been some rare but welcome good news concerning student lending. First, student loan growth has slowed to 4.7%oya, the first time in the series history that student loan growth has been slower than nominal GDP growth. Presumably the improving job situation has left fewer "labor market refugees" going back to school on loans. Second, newly delinquent loans recently slipped to 9.2% of current balances. This is still an extremely high number, but has fallen rapidly lately and is now at its lowest level since 2006.

Michael Feroli & Daniel Silver, JPMorgan Chase Bank, New York, NY

FOMC Minutes

We were looking for the minutes of the May FOMC meeting to provide context on the Committee's views on the trajectory of inflation, recent developments in financial conditions and implications for the path for policy, and views on balance sheet normalization in light of recent upward pressure on the effective federal funds rate. The minutes did not disappoint. Policymakers are not shaken up by the recent rise in inflation. They view this as being driven predominately by transitory factors, while measures of underlying trend inflation remain below 2%. Indeed, "a temporary period of inflation modestly above 2 percent...could be helpful". The Committee broadly recognized that financial conditions had tightened since the March meeting, but remained accommodative, and "had not materially altered their assessment of the outlook for the economy." Message received: the FOMC is intent on a June rate hike.

With time on their hands, policymakers diverted their focus to frameworks for policy implementation. Normalization of the Fed's balance sheet, in conjunction with other factors, has put upward pressure on the effective federal funds rate relative to the interest rate on excess reserves (IOER). As a quick fix, policymakers "generally agreed...to make a small technical adjustment" to policy mechanics. At a time when the FOMC raises the target range for the federal funds rate by 25bp, they would raise IOER by only 20bp in order to keep the effective federal funds rate well within the target range.

Excitement over fiscal stimulus has dimmed. Policymakers expressed uncertainty about the timing and size of the impacts from recent changes in fiscal policy. This seems like a shift from the more unambiguous stress on fiscal tailwinds expressed earlier this year. Moreover, policymakers expressed outright worry about trade policy uncertainty and its impact on the outlook. Beyond the next several years, "several participants...saw the trajectory of fiscal policy...as difficult to forecast."

The overall tone of the minutes carried a dovish tinge with respect to medium-term policy. Nothing in the minutes suggests that anything other than the gradual pace of policy tightening will continue. But there's more uncertainty about how much is needed over the medium-term, particularly as "some participants" believed that the forward guidance in the statement that policy remains accommodative and rates would likely remain below longer-run normal levels for some time is on the chopping block. That's just a change in the *description* of policy not a change in *actual* policy, and needs to be removed as they get closer to neutral. In our view, the fact that "some" are already arguing that this language is removed, means that "some" view the Fed is not far from the end of its tightening cycle.

Ellen Zenter, Morgan Stanley, New York, NY

May FOMC Minutes Show Increased Confidence in a Broadly Unchanged Outlook

The minutes of the May FOMC meeting indicated a continued upbeat view on the growth outlook among the Committee and the staff. Participants continued to describe growth as "moderate" and job gains as "strong," but they also acknowledged some softness in consumer spending—which was expected to "prove temporary." Both the staff and participants described risks to the economic outlook as roughly balanced but pointed to fiscal and trade policy as sources of uncertainty. Participants noted the difficulty involved in assessing the timing and magnitude of the effects of recent fiscal policy changes on the labor market and investment. Participants also noted that the outcomes from potential changes to trade policy are "particularly wide," and some noted that this uncertainty may lead to postponed or dampened capital spending. Despite these risks, participants noted "a number" of tailwinds supporting "continued above-trend" growth.

While the staff lowered its medium-term inflation forecast "a bit," this reflected "a touch" higher unemployment forecasts that are now arguably stale, given the 0.2pp subsequent drop in the jobless rate. Echoing the statement, the minutes noted that inflation had moved "close to 2 percent," which "most" participants found reassuring—though "several" noted the possible role of "transitory price changes" in healthcare and financial services. More generally, "participants" commented that the incoming data had "increased their confidence" in a sustained return of inflation to "near" 2 percent. Participants also viewed the Q1 employment cost index as an indication that the strong labor market was "showing through" to wage growth (despite the lack of uniformity across wage measures). The minutes also referenced a broadening in worker shortages—from "a few" to "a number" of districts.

In light of the recent move in the effective federal funds rate toward the top of the target range, the Committee discussed "a small technical realignment" of the interest rate on excess reserves (IOER) in order to keep the effective fed funds rate within the range. The deputy manager suggested this could be implemented by either (1) lowering IOER by 5 basis points at a meeting in which the FOMC decided to leave the target rate for the fed funds rate unchanged or (2) raising IOER by a smaller 20bp at a time when raising the target range for the fed funds rate by 25bp. Participants generally agreed that such a change would be appropriate "sooner rather than later," and we believe implementation is indeed likely at the June meeting (this would be consistent with the post-minutes rally in near-term Fed Funds futures). Making the adjustment at a meeting when the FOMC decided to hike rates was viewed as a simpler alternative to communicate, adding that IOER "does not, in itself, convey the stance of policy." Additionally, "a number of participants" raised that the Committee may want to discuss how to policy "most effectively and efficiently when the quantity of reserve balances reaches a level appreciably below that seen in recent years."

The incremental information in the minutes on the medium-term outlook for monetary policy was mixed to slightly dovish, in our view. "Participants" continued to view further gradual tightening as appropriate "if the economy evolves about as expected." However, "it was also noted" that a modest inflation overshoot could be "helpful" from the perspective of the Committee's objectives. "Some" members also noted the potential staleness of the forward guidance section of the statement—which currently suggests interest rates will "remain, for some time, below" longer-run levels and holds that "the stance of monetary policy remains accommodative." At the same time, given the increased confidence expressed in the inflation outlook and the risk assessed by "some" participants that supply constraints could "intensify" price and wage pressures, the net implications for the policy outlook were somewhat ambiguous.

Given the increased confidence in the inflation outlook but more dovish commentary on forward guidance and the potential desirability of a modest inflation overshoot, we left our subjective odds of a June hike unchanged at 95%.

Jan Hatizus, Goldman Sachs, New York, NY

Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2020 through 2024 and averages for the five-year periods 2020-2024 and 2025-2029. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		-----------Average For The Year------------					Five-Year Averages	
Interest Rates		**2020**	**2021**	**2022**	**2023**	**2024**	**2020-2024**	**2025-2029**
1. Federal Funds Rate	**CONSENSUS**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**
	Top 10 Average	3.5	3.6	3.6	3.5	3.5	3.5	3.5
	Bottom 10 Average	2.6	2.5	2.4	2.4	2.6	2.5	2.6
2. Prime Rate	**CONSENSUS**	**6.1**	**6.0**	**6.0**	**6.0**	**6.1**	**6.0**	**6.0**
	Top 10 Average	6.5	6.6	6.6	6.5	6.5	6.6	6.5
	Bottom 10 Average	5.6	5.5	5.4	5.5	5.6	5.5	5.6
3. LIBOR, 3-Mo.	**CONSENSUS**	**3.3**	**3.3**	**3.3**	**3.3**	**3.4**	**3.3**	**3.3**
	Top 10 Average	3.7	3.9	4.0	3.9	3.9	3.9	3.8
	Bottom 10 Average	2.9	2.8	2.7	2.7	2.9	2.8	2.9
4. Commercial Paper, 1-Mo.	**CONSENSUS**	**3.1**	**3.2**	**3.1**	**3.1**	**3.2**	**3.1**	**3.2**
	Top 10 Average	3.5	3.7	3.7	3.7	3.7	3.6	3.6
	Bottom 10 Average	2.7	2.6	2.6	2.6	2.7	2.6	2.7
5. Treasury Bill Yield, 3-Mo.	**CONSENSUS**	**3.0**	**3.0**	**2.9**	**2.9**	**3.0**	**3.0**	**3.0**
	Top 10 Average	3.5	3.6	3.6	3.5	3.6	3.5	3.5
	Bottom 10 Average	2.5	2.4	2.4	2.4	2.5	2.4	2.5
6. Treasury Bill Yield, 6-Mo.	**CONSENSUS**	**3.1**	**3.1**	**3.1**	**3.1**	**3.2**	**3.1**	**3.2**
	Top 10 Average	3.6	3.7	3.7	3.7	3.7	3.7	3.7
	Bottom 10 Average	2.7	2.6	2.5	2.5	2.7	2.6	2.7
7. Treasury Bill Yield, 1-Yr.	**CONSENSUS**	**3.2**	**3.3**	**3.2**	**3.2**	**3.3**	**3.2**	**3.3**
	Top 10 Average	3.7	3.8	3.8	3.8	3.8	3.8	3.9
	Bottom 10 Average	2.8	2.7	2.6	2.7	2.8	2.7	2.8
8. Treasury Note Yield, 2-Yr.	**CONSENSUS**	**3.4**	**3.4**	**3.4**	**3.4**	**3.4**	**3.4**	**3.5**
	Top 10 Average	3.9	4.0	4.0	3.8	4.0	3.9	4.1
	Bottom 10 Average	2.9	2.9	2.8	2.8	2.9	2.8	2.9
10. Treasury Note Yield, 5-Yr.	**CONSENSUS**	**3.6**	**3.6**	**3.6**	**3.6**	**3.7**	**3.6**	**3.8**
	Top 10 Average	4.0	4.1	4.1	4.1	4.2	4.1	4.4
	Bottom 10 Average	3.2	3.2	3.0	3.1	3.2	3.1	3.2
11. Treasury Note Yield, 10-Yr.	**CONSENSUS**	**3.8**	**3.8**	**3.8**	**3.8**	**3.8**	**3.8**	**3.9**
	Top 10 Average	4.3	4.3	4.4	4.3	4.4	4.3	4.5
	Bottom 10 Average	3.3	3.3	3.2	3.2	3.3	3.2	3.4
12. Treasury Bond Yield, 30-Yr.	**CONSENSUS**	**4.1**	**4.2**	**4.2**	**4.2**	**4.2**	**4.2**	**4.4**
	Top 10 Average	4.7	4.7	4.7	4.8	4.8	4.7	5.0
	Bottom 10 Average	3.6	3.6	3.6	3.6	3.7	3.6	3.7
13. Corporate Aaa Bond Yield	**CONSENSUS**	**5.2**	**5.2**	**5.2**	**5.3**	**5.4**	**5.3**	**5.4**
	Top 10 Average	5.7	5.8	5.9	6.0	6.0	5.9	6.0
	Bottom 10 Average	4.7	4.7	4.6	4.6	4.7	4.6	4.7
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.0**	**6.0**	**6.1**	**6.2**	**6.1**	**6.3**
	Top 10 Average	6.6	6.8	6.9	7.0	7.0	6.9	7.0
	Bottom 10 Average	5.3	5.3	5.3	5.3	5.4	5.3	5.4
14. State & Local Bonds Yield	**CONSENSUS**	**4.6**	**4.5**	**4.5**	**4.5**	**4.6**	**4.5**	**4.6**
	Top 10 Average	5.1	5.1	5.1	5.1	5.1	5.1	5.2
	Bottom 10 Average	4.0	3.9	3.9	4.0	4.1	4.0	4.1
15. Home Mortgage Rate	**CONSENSUS**	**5.4**	**5.4**	**5.4**	**5.4**	**5.5**	**5.4**	**5.6**
	Top 10 Average	5.8	5.9	6.0	6.0	6.0	6.0	6.1
	Bottom 10 Average	4.9	4.9	4.8	4.8	4.9	4.9	5.0
A. FRB - Major Currency Index	**CONSENSUS**	**89.6**	**89.4**	**89.6**	**90.0**	**90.1**	**89.7**	**90.4**
	Top 10 Average	94.3	94.6	94.5	94.5	94.5	94.5	94.8
	Bottom 10 Average	84.6	84.0	84.3	85.4	85.6	84.8	85.9

		----------Year-Over-Year, % Change----------					Five-Year Averages	
		2020	**2021**	**2022**	**2023**	**2024**	**2020-2024**	**2025-2029**
B. Real GDP	**CONSENSUS**	**1.9**	**1.9**	**2.0**	**2.1**	**2.1**	**2.0**	**2.1**
	Top 10 Average	2.4	2.4	2.4	2.4	2.5	2.4	2.4
	Bottom 10 Average	1.5	1.3	1.5	1.8	1.8	1.6	1.8
C. GDP Chained Price Index	**CONSENSUS**	**2.2**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.4	2.4	2.3	2.2	2.3	2.3	2.2
	Bottom 10 Average	2.0	2.0	2.0	1.9	2.0	2.0	2.0
D. Consumer Price Index	**CONSENSUS**	**2.3**	**2.3**	**2.3**	**2.2**	**2.2**	**2.3**	**2.2**
	Top 10 Average	2.7	2.6	2.5	2.4	2.5	2.5	2.4
	Bottom 10 Average	1.9	2.0	2.1	2.0	2.0	2.0	2.1

Databank:

2018 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	-0.2	0.0	0.8	0.3								
Auto & Light Truck Sales (b)	17.08	16.97	17.37	17.07								
Personal Income (a, current $)	0.4	0.3	0.3									
Personal Consumption (a, current $)	0.2	0.0	0.4									
Consumer Credit (e)	4.7	4.3	3.6									
Consumer Sentiment (U. of Mich.)	95.7	99.7	101.4	98.8								
Household Employment (c)	409	785	-37	3								
Non-farm Payroll Employment (c)	176	324	135	164								
Unemployment Rate (%)	4.1	4.1	4.1	3.9								
Average Hourly Earnings (All, cur. $)	26.71	26.74	26.80	26.84								
Average Workweek (All, hrs.)	34.4	34.5	34.5	34.5								
Industrial Production (d)	2.7	3.4	3.7	3.5								
Capacity Utilization (%)	76.9	77.1	77.6	78.0								
ISM Manufacturing Index (g)	59.1	60.8	59.3	57.3								
ISM Non-Manufacturing Index (g)	59.9	59.5	58.8	56.8								
Housing Starts (b)	1.339	1.290	1.336	1.287								
Housing Permits (b)	1.377	1.323	1.377	1.352								
New Home Sales (1-family, c)	633	659	672	662								
Construction Expenditures (a)	1.7	1.0	-1.7									
Consumer Price Index (nsa., d)	2.1	2.2	2.4	2.5								
CPI ex. Food and Energy (nsa., d)	1.8	1.8	2.1	2.1								
Producer Price Index (n.s.a., d)	2.7	2.8	3.0	2.6								
Durable Goods Orders (a)	-3.6	3.5	2.6									
Leading Economic Indicators (g)	0.8	0.7	0.4	0.4								
Balance of Trade & Services (f)	-56.7	-57.7	-49.0									
Federal Funds Rate (%)	1.29	1.42	1.49	1.69								
3-Mo. Treasury Bill Rate (%)	1.43	1.57	1.73	1.79								
10-Year Treasury Note Yield (%)	2.56	2.86	2.84	2.86								

2017 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.5	-0.2	0.1	0.3	0.0	-0.1	0.5	-0.1	2.0	0.7	0.8	-0.1
Auto & Light Truck Sales (b)	17.34	17.33	16.72	16.97	16.70	16.61	16.69	16.02	18.49	18.00	17.42	17.75
Personal Income (a, current $)	0.4	0.5	0.3	0.1	0.3	0.0	0.4	0.3	0.5	0.4	0.3	0.4
Personal Consumption (a, current $)	0.2	0.1	0.5	0.3	0.2	0.1	0.3	0.2	1.0	0.3	0.7	0.5
Consumer Credit (e)	3.1	5.2	4.7	3.9	5.8	3.7	5.7	3.7	5.7	5.8	9.8	6.0
Consumer Sentiment (U. of Mich.)	98.5	96.3	96.9	97.0	97.1	95.1	93.4	96.8	95.1	100.7	98.5	95.9
Household Employment (c)	-157	435	553	97	-269	358	261	-40	853	-478	71	104
Non-Farm Payroll Employment (c)	259	200	73	175	155	239	190	221	14	271	216	175
Unemployment Rate (%)	4.8	4.7	4.5	4.4	4.3	4.3	4.3	4.4	4.2	4.1	4.1	4.1
Average Hourly Earnings (All, cur. $)	25.99	26.07	26.11	26.17	26.21	26.26	26.34	26.39	26.51	26.47	26.54	26.64
Average Workweek (All, hrs.)	34.4	34.4	34.3	34.4	34.4	34.4	34.4	34.4	34.3	34.4	34.5	34.5
Industrial Production (d)	-0.5	-0.1	1.2	2.0	2.1	1.9	1.5	1.1	1.3	2.6	3.4	2.8
Capacity Utilization (%)	75.4	75.1	75.5	76.2	76.2	76.2	76.1	75.7	75.7	76.8	77.1	77.3
ISM Manufacturing Index (g)	56.0	57.6	56.6	55.3	55.5	56.7	56.5	59.3	60.2	58.5	58.2	59.3
ISM Non-Manufacturing Index (g)	56.5	57.4	55.6	57.3	57.1	57.2	54.3	55.2	59.4	59.8	57.3	56.0
Housing Starts (b)	1.236	1.288	1.189	1.154	1.129	1.217	1.185	1.172	1.159	1.261	1.299	1.207
Housing Permits (b)	1.300	1.219	1.260	1.228	1.168	1.275	1.230	1.272	1.225	1.316	1.303	1.300
New Home Sales (1-family, c)	599	615	638	593	604	616	556	558	637	618	712	636
Construction Expenditures (a)	0.8	1.9	0.3	-1.8	1.6	-0.8	-0.9	0.5	1.3	0.1	1.2	0.8
Consumer Price Index (s.a., d)	2.5	2.7	2.4	2.2	1.9	1.6	1.7	1.9	2.2	2.0	2.2	2.1
CPI ex. Food and Energy (s.a., d)	2.3	2.2	2.0	1.9	1.7	1.7	1.7	1.7	1.7	1.8	1.7	1.8
Producer Price Index (n.s.a., d)	1.7	2.0	2.2	2.5	2.3	1.9	2.0	2.4	2.6	2.8	3.0	2.5
Durable Goods Orders (a)	2.4	1.4	2.4	-0.8	0.0	6.4	-6.8	2.1	2.4	-0.4	1.7	2.7
Leading Economic Indicators (g)	0.6	0.5	0.4	0.2	0.3	0.6	0.3	0.4	0.1	1.3	0.4	1.6
Balance of Trade & Services (f)	-48.7	-44.4	-44.7	-48.1	-47.8	-45.6	-45.4	-44.6	-45.3	-49.1	-50.9	-53.9
Federal Funds Rate (%)	0.65	0.66	0.76	0.90	0.90	1.03	1.15	1.15	1.16	1.15	1.15	1.29
3-Mo. Treasury Bill Rate (%)	0.51	0.53	0.73	0.80	0.90	1.02	1.09	1.04	1.06	1.09	1.23	1.33
10-Year Treasury Note Yield (%)	2.43	2.43	2.47	2.30	2.31	2.19	2.32	2.33	2.28	2.36	2.36	2.40

(a) month-over-month % change; (b) millions, saar; (c) month-over-month change, thousands; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Calendar Of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
May 28 **Memorial Day** **U.S. Markets Closed**	**29** Dallas Fed Manufacturing (May) Consumer Confidence (May, Conference Board)	**30** ADP Employment (May) Real GDP (Q1, Second) Advance Economic Indicators (Apr) Dallas Fed Services (May) Beige Book EIA Crude Oil Stocks Mortgage Applications	**31** Personal Income and Consumption (Apr) Chicago PMI (May) Pending Home Sales (Apr) Weekly Jobless Claims Weekly Money Supply	**June 1** Employment (May) Manufacturing PMI (May, Final) ISM Manufacturing (May) Light Vehicle Sales (May) Construction Expenditures (Apr)
4 Factory Orders (Apr)	**5** Services PMI (May, Final) ISM Non-Manufacturing (May) JOLTS (Apr)	**6** International Trade (Apr) Productivity and Costs (Q1, Revised) EIA Crude Oil Stocks Mortgage Applications	**7** Consumer Credit (Apr) Quarterly Services Survey (Q1) Weekly Jobless Claims Weekly Money Supply	**8** Wholesale Trade (Apr)
11	**12** **FOMC Meeting** Consumer Price Index (May) NFIB Survey (May) Federal Budget (May)	**13** **FOMC Meeting** **Statement and Projections (2:00 pm)** **Press Conference (2:30 pm)** Producer Price Index (May) EIA Crude Oil Stocks Mortgage Applications	**14** Retail Sales (May) Import Prices (May) Business Inventories (Apr) Weekly Jobless Claims Weekly Money Supply	**15** Industrial Production (May) Empire State Manufacturing (Jun) Consumer Sentiment (Jun, Preliminary, Univ. of Michigan) TIC Data (Jun)
18 Business Leaders Survey (Jun) NAHB survey (Jun)	**19** Housing Starts (May)	**20** Existing Home Sales (May) Current Account (Q1) EIA Crude Oil Stocks Mortgage Applications	**21** Philadelphia Fed Manufacturing Survey (Jun) FHFA Home Price Index (Apr) Weekly Jobless Claims Weekly Money Supply	**22** IHSMarkit Manufacturing PMI (Jun, Flashl) IHSMarkit Services PMI (Jun, Flash))
25 New Home Sales (May) Dallas Fed Manufacturing (Jun)	**26** Philadelphia Fed Nonmanufacturing (Jun) S&P/Case-Shiller Home Price Index (Apr) Consumer Confidence (Jun, Conference Board Richmond Fed Survey (Jun) Dallas Fed Services (Jun) Consumer Confidence (May, Conference Board)	**27** Durable Goods (May) Advance Economic Indicators (May) Pending Home Sales (May) EIA Crude Oil Stocks Mortgage Applications	**28** Real GDP (Q1, 3rd estimate) Kansas City Fed Survey (Jun) Weekly Jobless Claims Weekly Money Supply	**29** Personal Income and Consumption (May) Chicago PMI (Jun) Consumer Sentiment ((Jun, Final, Univ. of Michigan)
July 2 ISM Manufacturing (Jun) IHSMarkit Manufacturing (Jun) Construction Spending (May)	**3** Factory Orders ((May) Light Vehicle Sales (Jun)	**4** **Independence Day** **Markets Closed**	**5** **FOMC Minutes** ADP Employment (Jun) IHSMarkit Services PMI (Jun, Final) ISM Nonmanufacturing (Jun) EIA Crude Oil Stocks Mortgage Applications Weekly Jobless Claims Weekly Money Supply	**6** Employment (Jun) International Trade (May)

BLUE CHIP FORECASTERS

CONTRIBUTORS TO DOMESTIC SURVEY

ACIMA Private Wealth, Richmond, VA
Ardavan Mobasheri

Action Economics, LLC, Boulder, CO
Michael Englund

AIG, New York, NY
Henry Mo, Jerry Cai

Amherst Pierpont Securities, Stamford, CT
Stephen Stanley

Bank of America Merrill Lynch, New York, NY
Ethan Harris

Barclays, New York, NY
Michael Gapen

BMO Capital Markets Economics, Toronto, Canada
Douglas Porter

BNP Paribas North America, New York, NY
Paul Mortimer-Lee, Bricklin Dwyer, Laura Rosner, and Derek Lindsey

Chase Wealth Management, New York, NY
Anthony Chan

Chmura Economics & Analytics, Richmond, VA
Christine Chmura and Xiaobing Shuai

Comerica, Dallas, TX
Robert A. Dye

Cycledata Corp., San Diego, CA
Robert S. Powers

Daiwa Capital Markets America, New York, NY
Michael Moran

DePrince & Associates, Murfreesburo, TN
Albert E. DePrince Jr.

Economist Intelligence Unit, New York, NY
Leo Abruzzese and Jan Friederich

Fannie Mae, Washington, DC
Douglas Duncan

Georgia State University, Atlanta, GA
Rajeev Dhawan

GLC Financial Economics, Providence, RI
Gary L. Ciminero

Goldman, Sachs & Co., New York, NY
Jan Hatzius

Grant Thornton/Diane Swonk, LLC, Chicago, IL
Diane Swonk

High Frequency Economics, Valhalla NY
James O'Sullivan

J.P. Morgan Chase, New York, NY
Bruce Kasman

Loomis, Sayles & Company, L.P., Boston, MA
Brian Horrigan

MacroFin Analytics, Wayne, NJ
Parul Jain

Moody's Analytics, West Chester, PA
Mark M. Zandi

Moody's Capital Markets Group, New York, NY
John Lonski

MUFG Union Bank, New York, NY
Christopher S. Rupkey

Naroff Economic Advisors, Philadelphia, PA
Joel L. Naroff

National Association of Realtors, Washington, DC
Lawrence Yun and George Ratiu

NatWest Markets, Greenwich, CT
Michelle Girard and Kevin Cummins

Nomura Securities International, Inc., New York, NY
Lewis Alexander

Oxford Economics, New York, NY
Gregory Daco

PNC Financial Services Group, Pittsburgh, PA
Gus Faucher

RBC Capital Markets, New York, NY
Thomas Porcelli

RDQ Economics, New York, NY
John Ryding and Conrad DeQuadros

Regions Financial Corporation, Birmingham, AL
Richard F. Moody

Scotiabank Group, Toronto, Canada
Jean-Francois Perrault and Brett House

Societe Generale, NY, New York
Stephen W. Gallagher

S&P Global, New York, NY
Beth Ann Bovino

Stone Harbor Investment Partners, LP, New York, NY
Brian Keyser

Swiss Re, New York, NY
Jerome Haegeli

The Northern Trust Company, Chicago, IL
Carl Tannenbaum

UBS AG, New York, NY
Seth Carpenter

Via Nova Management, Richmond, VA
Alan Gayle

Wells Capital Management, San Francisco, CA
Gary Schlossberg

Wells Fargo, Charlotte, NC
John Silvia and Mark Vitner

CONTRIBUTORS TO INTERNATIONAL SURVEY

AIG, New York, NY
Barclays Capital, New York, NY
BNP Paribas Americas, New York, NY
IHS-Markit, London, U.K.
ING Financial Markets, London, England
Mizuho Research Institute, Tokyo, Japan
Moody's Analytics, West Chester, PA
Moody's Capital Markets Group, New York, NY
Nomura Securities International, New York, NY
Oxford Economics, Wayne, PA
Scotiabank Group, Toronto, Canada
UBS, New York, NY
Wells Fargo, Charlotte, NC

150 FERC ¶ 61,165
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, Tony Clark,
Norman C. Bay, and Colette D. Honorable.

Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group — Docket Nos. EL11-66-002

v.

Bangor Hydro-Electric Co.; Central Maine Power Co.; New England Power Co.; New Hampshire Transmission LLC; NSTAR Electric and Gas Corp.; Northeast Utilities Service Co.; The United Illuminating Co.; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Co.; Vermont Transco, LLC

Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; — EL11-66-003

Power Options, Inc.; and the Industrial Energy
Consumer Group

v.

Bangor Hydro-Electric Co.; Central Maine Power Co.;
New England Power Co.; New Hampshire Transmission
LLC; NSTAR Electric and Gas Corp.; Northeast
Utilities Service Co.; The United Illuminating Co.;
Unitil Energy Systems, Inc. and Fitchburg Gas and
Electric Light Co.; Vermont Transco, LLC

OPINION NO. 531-B

ORDER ON REHEARING

(Issued March 3, 2015)

Table of Contents

1. On July 21, 2014, the New England Transmission Owners (NETOs),[1] a group of complainants (Complainants) and intervenors (collectively, Petitioners),[2] and the Eastern

[1] The NETOs include Bangor Hydro-Elec. Co.; Central Maine Power Co.; New England Power Co.; New Hampshire Transmission LLC; NSTAR Electric & Gas Corp.; Northeast Utilities Service Co.; United Illuminating Co.; Unitil Energy Systems, Inc. and Fitchburg Gas & Electric Light Co.; and Vermont Transco, LLC.

[2] Complainants include Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Co.; Associated Industries of Massachusetts; the Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group. Intervenors

(continued…)

Massachusetts Consumer-Owned Systems (EMCOS), filed requests for rehearing of the Commission's June 19, 2014 order on initial decision[3] concerning a complaint, filed pursuant to section 206 of the Federal Power Act (FPA),[4] challenging the NETOs' base return on equity (ROE) reflected in ISO New England Inc.'s (ISO-NE) open access transmission tariff (OATT).[5] In this order, we deny rehearing.

I. Background

2. The NETOs recover their transmission revenue requirements through formula rates included in ISO-NE's OATT. The revenue requirements for Regional Network Service[6] and Local Network Service[7] that the NETOs provide are calculated using the same single base ROE. On October 31, 2006, the Commission, in Opinion No. 489, established the base ROE at 11.14 percent, which consisted of an initial base ROE of 10.4 percent plus an upward adjustment of 74 basis points to account for changes in capital market conditions that took place between the issuance of the Administrative Law Judge's initial decision in that proceeding and the issuance of Opinion No. 489,[8] as reflected in changes in U.S. Treasury bond yields during that time period.

New Hampshire Electric Cooperative, Inc. and Maine Public Utilities Commission requested rehearing jointly with the Complainants.

[3] *Martha Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234 (2014) (Opinion No. 531), *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014) (Opinion No. 531-A).

[4] 16 U.S.C. § 824e (2012).

[5] ISO-NE's OATT is section II of ISO-NE's Transmission, Markets, and Services Tariff (Tariff). *See* ISO-NE, Tariff, § II.

[6] Regional Network Service is the transmission service over the pool transmission facilities described in Part II.B of the OATT. ISO-NE, Tariff, § I.2 (50.0.0); *see also* ISO-NE, Tariff, § II.B Regional Network Service (0.0.0), *et seq.*

[7] Local Network Service is the network service provided under Schedule 21 and the Local Service Schedules of ISO-NE's OATT. ISO-NE, Tariff, § I.2 (50.0.0); *see also* ISO-NE, Tariff, Schedule 21 Local Service (1.0.0), *et seq.*

[8] *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006) (Opinion No. 489), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarification*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom. Conn. Dep't of Pub. Util. Control v. FERC*, 593 F.3d 30 (2010).

3. On September 30, 2011, the Complainants filed a complaint alleging that the NETOs' 11.14 percent base ROE was unjust and unreasonable because capital market conditions had significantly changed since that base ROE was established in 2006. The Complainants argued that the bubble in the U.S. housing market, the subsequent financial crisis and economic recession, and the fiscal and monetary policies of the U.S. government had caused a "flight to quality"[9] in the capital markets. The Complainants contended that these market conditions had lowered bond yields and, as a result, capital costs for utilities.[10] The Complainants argued that, as a result, the NETOs' 11.14 percent base ROE now exceeded the level necessary to satisfy the Supreme Court's standards in *Bluefield*[11] and *Hope*.[12] The Complainants asserted that, based on a discounted cash flow (DCF) analysis conducted by their expert witness, the just and reasonable base ROE for the NETOs should not exceed 9.2 percent.

4. On May 3, 2012, the Commission issued an order on the complaint, establishing hearing and settlement judge procedures.[13] The Hearing Order also set a refund effective date of October 1, 2011. The hearing commenced on May 6, 2012 and was completed on May 10, 2013.[14] In accordance with the hearing's procedural schedule, the participants each first submitted an ROE analysis,[15] based on data from a 6-month study period in

---

[9] The "flight to quality" refers to investors seeking low-risk investment vehicles.

[10] Complaint, Ex. C-1 at 5-12.

[11] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) (*Bluefield*).

[12] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*).

[13] *Martha Coakley, Mass. Attorney Gen.. v. Bangor Hydro-Elec. Co.*, 139 FERC ¶ 61,090 (2012) (Hearing Order).

[14] The parties conducted settlement negotiations but reached an impasse, leading to termination of the settlement procedures in August 2012. *Martha Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, 144 FERC ¶ 63,012, at P 28 (2013) (Initial Decision).

[15] The following expert witnesses submitted ROE analyses: Dr. William E. Avera, for the NETOs; Ms. Sabina U. Joe, for Trial Staff; Dr. John Wilson, for the EMCOS; and Dr. Randall Woolridge, for the Complainants.

2012,[16] and then filed an updated ROE analysis, using the same DCF methodology that each participant used in its initial analysis but with data based on the 6-month study period from October 2012 through March 2013.

5. On August 6, 2013, the Presiding Judge issued the initial decision, finding the NETOs' current 11.14 percent base ROE to be unjust and unreasonable.[17] The Presiding Judge adopted the DCF methodology used by the NETOs and found that it is appropriate to establish two different base ROEs in this proceeding—one for the 15-month refund period from October 1, 2011 (i.e., the refund effective date) to December 31, 2012, and one for the prospective period commencing when the Commission issues its order setting the going-forward base ROE. Thus, the Presiding Judge considered two separate DCF analyses relying on overlapping data from each period, the first using data from May 2012 through October 2012 and the second using data from October 2012 through March 2013. The Presiding Judge found the just and reasonable base ROE for the refund period to be 10.6 percent and the just and reasonable base ROE for the prospective period to be 9.7 percent.[18]

6. On June 19, 2014, the Commission issued Opinion No. 531, affirming in part and reversing in part the initial decision.[19] In Opinion No. 531, the Commission changed its approach on the DCF methodology to be applied in public utility rate cases, by adopting the two-step DCF methodology in place of the one-step DCF methodology the Commission had historically used. The Commission explained that the two-step DCF formula is k=D/P (1+.5g)+g, where "D/P," the dividend yield, is calculated using a single, average dividend yield based on the indicated dividend and the average monthly high and low stock prices over a six-month period; and "g," the constant dividend growth rate, is calculated by averaging short-term and long-term growth estimates, with the short-term estimate receiving two-thirds weight and the long-term estimate receiving one-third weight.[20]

---

[16] Due to the different due dates for the parties' initial briefs, which ranged from October 2012 to January 2013, each party's initial ROE analysis was based on a different 6-month period in 2012.

[17] Initial Decision, 144 FERC ¶ 63,012 at P 544.

[18] *Id.*

[19] *See generally* Opinion No. 531, 147 FERC ¶ 61,234.

[20] *Id.* PP 15, 17, 39.

7. The Commission, after finding that there should be only one base ROE applicable to both the refund period and the prospective period in this proceeding, then applied the two-step DCF methodology to the facts of this proceeding, using a national proxy group of companies the Commission found were of comparable risk to the NETOs, to determine the NETOs' base ROE; however, because the parties had not litigated one input to the two-step DCF methodology—i.e., the appropriate long-term growth projection—the Commission instituted a paper hearing on that narrow issue. The Commission also found that, due to the anomalous capital market conditions reflected in the record, mechanically applying the DCF methodology and placing the NETOs' base ROE at the midpoint of the zone of reasonableness produced by that methodology would not satisfy the requirements of *Hope* and *Bluefield*.[21] Therefore, the Commission found it appropriate, based on the record evidence in the proceeding, to place the NETOs' base ROE halfway between the midpoint of the zone of reasonableness and the top of that zone.[22] However, the Commission explained that its finding on the specific numerical just and reasonable ROE for the NETOs was subject to the outcome of the paper hearing on the appropriate long-term growth projection to be used in the two-step DCF methodology.[23] The Commission also explained that, according to Commission precedent, "when a public utility's ROE is changed, either under section 205 or section 206 of the FPA, that utility's total ROE, inclusive of transmission incentive ROE adders, should not exceed the top of the zone of reasonableness produced by the two-step DCF methodology."[24]

8. On October 16, 2014, the Commission issued Opinion No. 531-A, the order on the paper hearing instituted by Opinion No. 531, finding that long-term projected growth in gross domestic product (GDP) is the appropriate long-term growth projection to use in the two-step DCF methodology.[25] Accordingly, the Commission found that a just and reasonable ROE for the NETOs is 10.57 percent, and that the NETOs' total or maximum ROE, including transmission incentive ROE adders, cannot exceed 11.74 percent, i.e., the top of the zone of reasonableness in this proceeding.[26] The Commission also ordered the

---

[21] *Id.* P 142.

[22] *Id.*

[23] *Id.*

[24] *Id.* P 165.

[25] Opinion No. 531-A, 149 FERC ¶ 61,032 at P 10.

[26] *Id.* PP 10-11.

NETOs to issue refunds for the 15-month refund period from October 1, 2011 through December 31, 2012.[27]

II. Discussion

A. Procedural Matters

9. On July 21, 2014, the NETOs, Petitioners, and EMCOS filed requests for rehearing of Opinion No. 531. On November 17, 2014, the NETOs requested rehearing of Opinion No. 531-A, in Docket No. EL11-66-003, by submitting the same pleading that they filed on July 21, 2014 as a request for rehearing of Opinion No. 531.[28] Because the NETOs submitted the same pleading as a request for rehearing of both Opinion Nos. 531 and 531-A and, therefore, presented identical arguments in those two proceedings, our merits determinations in the instant order apply to the NETOs' requests for rehearing in both Docket Nos. EL11-66-002 and EL11-66-003. Thus, we also deny the NETOs' request for rehearing of Opinion No. 531-A.

1. Answers to Rehearing Requests, and Related Answers to Answers

10. On August 5, 2014, the Petitioners filed an answer to the NETOs' request for rehearing (Petitioners' August 5 Answer), and the NETOs filed an answer to the Petitioners' request for rehearing (NETOs' August 5 Answer). On August 20, 2014, the NETOs filed an answer to the Petitioners' August 5 Answer (NETOs' August 20 Answer).[29] On August 22, 2014, the Petitioners filed an answer to the NETOs' answer to the Petitioners' request for rehearing (Petitioners' August 22 Answer). On September 4, 2014, the Petitioners filed an answer to the NETOs' August 20 Answer (Petitioners' September 4 Answer).

---

[27] *Id.* PP 12, Ordering Paragraph (C).

[28] *See* NETOs, Request for Rehearing, Docket No. EL11-66-003, at 3 (filed Nov. 7, 2014) ("the NETOs seek rehearing of Opinion No. 531-A with respect to the same issues and on the same grounds upon which they sought rehearing of Opinion No. 531. These issues and grounds are set forth in the NETOs' 'Request for Rehearing and Motion for Clarification of the New England Transmission Owners,' which the NETOs filed with the Commission on July 21, 2014, and which is attached hereto and incorporated herein (*see* Attachment A)").

[29] While the NETOs' August 20 Answer was styled as a motion to clarify the record, the filing was, in substance, an answer to the Complainants' August 5 Answer.

11. Rule 713(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d) (2014), prohibits answers to a request for rehearing. Therefore, we reject the Petitioners' August 5 Answer and the NETOs' August 5 Answer. Accordingly, we also reject the answers to those answers—specifically, the NETOs' August 20 Answer, the Petitioners' August 22 Answer, and the Petitioners' September 4 Answer.

2. Motion to Strike

12. On August 5, 2014, the NETOs filed a motion to strike certain extra-record evidence from the Petitioners' request for rehearing. On August 20, 2014, the Petitioners filed an answer opposing the NETOs' motion to strike. We grant in part and deny in part the NETOs' motion to strike. The Commission has consistently held that the submission of additional factual information in a request for rehearing is inappropriate.[30] Therefore, we grant the NETOs' motion with respect to the extra-record evidence in Petitioners' request for rehearing. However, we deny the NETOs' motion with respect to the evidence that was already in the record and that Petitioners have merely reframed through graphical representation or basic arithmetic.[31]

3. Motions to Intervene Out-of-Time

13. On July 21, 2014, American Municipal Power, Inc. (AMP) filed a motion to intervene out-of-time and a request for rehearing,[32] and the American Public Power Association (APPA) and the National Rural Electric Cooperative Association (NRECA) jointly filed a motion to intervene out-of-time. APPA and NRECA also joined in the Petitioners' request for rehearing. On August 5, 2014, the NETOs filed an answer

---

[30] *E.g., Transcontinental Gas Pipe Line Corp.*, 94 FERC ¶ 61,066, at 61,278 (2001).

[31] Specifically, we deny the NETOs' motion with respect to (1) the altered version of the NETOs' risk premium analysis, at page 38 and Attachment A of Petitioners' request for rehearing; (2) the altered version of Opinion No. 531's Appendix showing an alternate source of growth rate projections, at pages 43 and 51, and at Attachment B, of Petitioners' request for rehearing; (3) the altered version of Opinion No. 531's Appendix reflecting an alternate low-end outlier adjustment, at pages 14, 62, and 63, and at Attachment C, of Petitioners' request for rehearing; (4) the altered version of Exhibit SC-524, at pages 26 and 27 of Petitioners' request for rehearing; (5) the histogram at pages 2-3 of Petitioners' request for rehearing; and (6) the histogram on pages 24-25 of Petitioners' request for rehearing.

[32] While AMP styled its filing as a motion for clarification, it is in substance a request for rehearing.

opposing AMP's, APPA's, and NRECA's motions to intervene out-of-time, and AMP's request for rehearing. On August 12, 2014, APPA and NRECA filed an answer to the NETOs' answer to the motions to intervene out of time and AMP's request for rehearing. On December 5, 2014, the Maine Public Advocate Office filed a motion to intervene out-of-time.

14. In ruling on a late-filed motion to intervene, the Commission applies the criteria set forth in Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2014), and considers, among other things, whether the movant had good cause for failing to file the motion within the time prescribed, whether any disruption to the proceeding might result from permitting the intervention, and whether any prejudice to or additional burdens upon the existing parties might result from permitting the intervention. A petitioner for late intervention bears a higher burden to show good cause for late intervention after the Commission has issued a final order in a proceeding, and it is the Commission's policy to deny late intervention at the rehearing stage, even when the movant claims that the decision establishes a broad policy of general application.[33]

15. We find that AMP, APPA, NRECA, and the Maine Public Advocate Office have not met their burden of justifying late intervention. The Complainants filed the complaint in this proceeding on September 30, 2011, alleging that the capital market conditions following the collapse of the housing bubble and the resulting economic recession were such that the NETOs' existing ROE was no longer just and reasonable; the Commission then set the complaint for hearing on May 30, 2012 and issued a dispositive order on June 19, 2014, nearly three years after the complaint was filed. Thus, AMP, APPA, NRECA, and the Maine Public Advocate Office had ample notice that this proceeding involved the Commission's approach to determining public utilities' ROE, that the effect of recent capital market conditions on that approach was an issue central to the complaint, and that a Commission order in this proceeding would have precedential effect on similar proceedings before the Commission. AMP, APPA, NRECA, and the Maine Public Advocate Office have not shown good cause for failing to file their motions to intervene during the statutory comment period, or subsequent to that period but prior to the Commission's issuance of Opinion No. 531. AMP's, APPA's, and NRECA's statements that they did not anticipate the specific outcome in this proceeding, without more, do not suffice to make that showing.[34] We therefore deny their late-filed motions to intervene.

---

[33] *See, e.g., Williston Basin Interstate Pipeline Co.*, 112 FERC ¶ 61,038, at P 12 (2005).

[34] APPA and NRECA cite *Duke Energy Carolinas, LLC, et al.*, 147 FERC ¶ 61,241 (2014) (*Duke*), as an example of an instance where the Commission has allowed a national organization's late intervention due to an order's far-reaching impacts. However, we find *Duke* to be distinguishable from the instant case. In *Duke*, the National

(continued…)

Correspondingly, we also deny AMP's, APPA's, and NRECA's requests for rehearing, because under Rule 713(b) the Commission's Rules of Practice and Procedure only a party to a proceeding may seek rehearing. [35]

B. Substantive Matters

16. The arguments raised on rehearing involve issues concerning the burden of proof, placement of the NETOs' base ROE within the zone of reasonableness, the impact of the change in DCF methodology on the NETOs' existing transmission incentive ROE adders, and the timing of the Commission's establishment of the just and reasonable rate in this proceeding. As discussed below, we deny rehearing on these issues.

1. Burden of Proof

a. Opinion No. 531

17. The Commission in Opinion No. 531 affirmed the Presiding Judge's determination on the burden of proof,[36] explaining that under FPA section 206 the burden to show that a rate is unjust and unreasonable "shall be on the Commission or the complainant,"[37] and, in the context of an ROE proceeding, the burden entails finding that the existing ROE is not "commensurate with returns on investments in other enterprises having corresponding risks . . . [and] sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[38] The Commission explained that, to estimate the return necessary to attract equity investors, the Commission uses the DCF

Association of Regulatory Utility Commissioners (NARUC) failed to intervene in an Order No. 1000 proceeding. NARUC explained that it had intervened in multiple Order No. 1000 proceedings, but that its failure to intervene in *Duke* could only have been avoided if NARUC had intervened in every Order No. 1000 proceeding. Unlike *Duke*, the instant proceeding was the first case of its kind to challenge utilities' base ROEs during the economic recession of 2007-2009, and AMP, APPA, and NRECA should have known that the proceeding could have precedential effect on other proceedings.

[35] 16 U.S.C. § 825(l) (2012); 18 C.F.R. § 385.713(b) (2014); *see, e.g., Southern Company Servs., Inc.*, 92 FERC ¶ 61,167 (2000).

[36] Opinion No. 531, 147 FERC ¶ 61,234 at P 49.

[37] *Id.* P 50 (quoting 16 U.S.C. § 824e (2012)).

[38] *Id.* P 50 (quoting *Hope*, 320 U.S. at 603).

model, which identifies a zone of reasonable returns.[39] The Commission rejected the NETOs' argument that the Commission "does not have the authority under FPA section 206 to change the existing base ROE unless the evidence shows that it is entirely outside the zone of reasonableness."[40] The Commission explained that not every ROE within the zone of reasonableness is just and reasonable, and that the zone of reasonableness identified by the DCF model "is simply the first step in the determination of a just and reasonable ROE for a utility or group of utilities."[41]

b. Request for Rehearing

18. The NETOs argue that, because the NETOs' existing ROE of 11.14 percent falls within the zone of reasonableness, the Commission erred in finding that the Complainants and Trial Staff have carried their burden of establishing that the existing ROE is unjust and unreasonable.[42] According to the NETOs, court and Commission precedent support a finding that an ROE within the zone of reasonableness remains just and reasonable.[43] The NETOs state that the Commission misunderstood their contention with respect to FPA sections 205 and 206. They assert that FPA section 206 carries a two-prong burden, the first of which is to show that the existing rate is unjust and unreasonable. The NETOs assert that interpreting FPA section 206 otherwise would eliminate the difference between the burdens of proof under FPA sections 205 and 206 by requiring a complainant to show only that its proposed rate is more just and reasonable than the existing rate. The NETOs concede that not all rates within the zone of reasonableness are equally just and reasonable, but also argue that it is not enough to show that there is a more just and reasonable rate than the existing rate; rather the complainant must demonstrate through substantial evidence that the existing rate does not fall within the zone of just and reasonable rates.[44] The NETOs contend that no party satisfied the first prong of FPA section 206.

---

[39] *Id.*

[40] *Id.* P 51.

[41] *Id.*

[42] NETOs Request for Rehearing at 26-27.

[43] *Id.* at 27-30 (citing *Me. Pub. Utils. Comm'n v. FERC*, 520 F.3d 464, 470-71 (D.C. Cir. 2008) (*Maine PUC*), *rev'd in part on other grounds sub nom. NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165 (2010); *Calpine Corp. v. Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,271, at P 41 (2009)).

[44] *Id.* at 36.

19. The NETOs assert that, in accordance with Commission and federal court precedent, any ROE within the zone of reasonableness cannot be found to be unjust and unreasonable. The NETOs further assert that the Commission erred in finding that the DCF zone of reasonableness is different from the zone of reasonableness under FPA section 206, and that the Commission has never before drawn a distinction between the DCF zone of reasonableness and the zone of reasonableness referred to when applying FPA section 206. The NETOs argue that determining the zone of reasonableness is not merely an intermediate step in a Commission-created DCF analysis whose final step is identification of a "pinpoint" just and reasonable ROE that the Commission believes is optimal in the context of that specific proceeding, but rather is identical to the zone of reasonableness used in FPA section 206 analyses. The NETOs state that in *Northeast Utilities Service Co.*, 124 FERC ¶ 61,044 (2008) (*Northeast Utilities*), *Central Maine Power Co.*, 125 FERC ¶ 61,079 (2008) (*Central Maine*), and *Desert Southwest Power, LLC*, 135 FERC ¶ 61,143 (2011) (*Desert Southwest*) the Commission explicitly identified the DCF zone of reasonableness with the more general zone of reasonableness used in the FPA section 206 context and treated the two as one and the same.[45]

20. The NETOs further argue that the Commission's reliance on *Bangor Hydro* to distinguish the DCF zone of reasonableness from the range of reasonableness under FPA section 206 is inappropriate because *Bangor Hydro* involved application of the last clean rate doctrine after the rate under consideration had been found to be unjust and unreasonable.[46] The NETOs argue that, if *Bangor Hydro* does mean that the DCF zone of reasonableness is not really a zone of reasonableness, then that case was wrongly decided because it would contradict Commission and court precedent, particularly the D.C. Circuit's decision in *City of Winnfield*.[47] The NETOs argue that, although Opinion No. 531 refers to the guidance on this issue in *City of Winnfield* as dicta, the Commission has relied on that guidance in previous decisions.[48] The NETOs argue that FPA section 206 carries a stricter burden of proof than FPA section 205, that the dual burden of proof

---

[45] *Id.* at 39.

[46] *Id.* at 41-42 (citing *Bangor Hydro-Electric Co.*, 122 FERC ¶ 61,038 (2008) (*Bangor Hydro*)).

[47] *Id.* at 42-43 (citing *City of Winnfield v. FERC*, 744 F.2d 871, 875-76 (D.C. Cir. 1984) (*City of Winnfield*)).

[48] *Id.* at 42 (citing *Texas Eastern Transmission Corp.*, 32 FERC ¶ 61,056, at 61,150 (1985); *Promoting Transmission Investment through Pricing Reform*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, at P 98 (2006) (cross-referenced at 117 FERC ¶ 61,345, at P 98 (2006)) (Order No. 679-A); *New Dominion Energy Coop.*, 118 FERC ¶ 63,024, at n.154 (2007)).

under section 206 provides statutory protection to utility companies, and therefore that Congress intended to create asymmetry between FPA sections 205 and 206.[49] Lastly, the NETOs argue that Opinion No. 531 reduces the clarity and predictability of the zone of reasonableness determination by instituting a method that is no longer limited by an objective formula. The NETOs argue that the resultant lack of predictability increases the perceived risk which is counter to *Hope* and *Bluefield*.[50]

c. Commission Determination

21. We deny rehearing on the issue of the burden of proof. The NETOs once again assert that an existing base ROE cannot be found unjust and unreasonable as long as it is within the zone of reasonableness produced by a DCF analysis, and that the Commission's rejection of this argument in Opinion No. 531 is contrary to court and Commission precedent. We disagree.

22. The NETOs cite precedent setting forth a general ratemaking principle that "there is not a single 'just and reasonable rate' but rather a zone of rates that are just and reasonable; a just and reasonable rate is one that falls within that zone."[51] The NETOs equate references to a "zone of rates that are just and reasonable" or a "zone of reasonableness" in those cases to the "zone of reasonableness" produced by the DCF analysis we use to determine the ROE to include in a public utility's cost of service. On that basis, the NETOs contend that the Commission must show that the NETOs' existing ROE is outside the DCF zone of reasonableness in order to satisfy its FPA section 206 burden to show that their ROE is unjust and unreasonable.

23. In *City of Winnfield* and *Maine PUC*, which did not involve the determination of ROE, the term "zone of reasonableness" was used to express the general principle that under the FPA there can be more than one just and reasonable rate for a service. For example, in the portion of *City of Winnfield* cited by the NETOs, the court addressed the issue of whether the rate for a power sale should be based on an incremental fuel cost or a system average fuel cost, and the court explained that if either methodology was just and

---

[49] *Id.* at 44 (citing *City of Winnfield*, 744 F.2d at 875).

[50] *Id.* at 45-46.

[51] *See, e.g.*, *Maine PUC*, 520 F.3d at 470-71 (upholding Commission determination that transition payments agreed to in a settlement redesigning New England's capacity market fell within a reasonable range of capacity prices); *City of Winnfield*, 744 F.2d at 875-76.

reasonable, the Commission could not force the utility to shift from one to the other in a section 206 proceeding.[52]

24. In determining the ROE component of a public utility's cost of service pursuant to a DCF analysis, however, the term "zone of reasonableness" has a particular, more technical meaning that differs from its meaning when used in general descriptions of what constitutes a just and reasonable rate charged by a public utility for jurisdictional service, such as in *City of Winnfield* and *Maine PUC*. The Commission uses a three-step process to determine the just and reasonable ROE component of the cost of service of a public utility or a group of public utilities. First, the Commission establishes a proxy group of companies of comparable risk. Second, the Commission performs a DCF analysis of each member of the proxy group in order to determine a "zone of reasonableness," within which to set a just and reasonable ROE. That DCF zone of reasonableness is the range from the lowest proxy member ROE to the highest proxy member ROE. Finally, the Commission establishes a just and reasonable ROE at a single point within the DCF zone of reasonableness.

25. Thus, in the context of determining an ROE, the establishment of the DCF zone of reasonableness is simply one step in the process of determining a just and reasonable ROE for inclusion in the cost of service of the subject public utility or utilities. Typically, the DCF zone of reasonableness is relatively broad. For example, in *Bangor Hydro*[53] setting the NETOs' existing ROE, the DCF zone of reasonableness was from 7.3 percent to 13.1 percent, or almost 600 basis points. In this case, the zone of reasonableness is from 7.03 percent to 11.74 percent, or nearly 500 basis points. Not every ROE within that relatively broad DCF "zone of reasonableness" is a just and reasonable ROE for the particular public utility or utilities at issue. As the Commission held in *Bangor Hydro*, "[c]ertain rates, though within the zone, may not be just and reasonable given the circumstances of the case."[54]

---

[52] *See City of Winnfield*, 744 F.2d at 875 ("in that circumstance the agency is effectively using § 205, which is intended for the benefit of the utility—i.e., as a means of enabling it to increase its rates within what has been called the 'zone of reasonableness'—for the quite different purpose of *depriving the utility* of the statutory protection contained in § 206, that its existing rates be found to be entirely outside the zone of reasonableness before the agency can dictate their level or form.") (emphasis in original) (citation omitted).

[53] 122 FERC ¶ 61,038 at PP 10-15.

[54] *Id.* P 11 (quoting *Montana-Dakota Utils. Co. v. Nw. Pub. Serv. Co.*, 341 U.S. 246, 251 (1951) (*Montana-Dakota*)).

26. The decision of the United States Court of Appeals for the District of Columbia Circuit in *S. Cal. Edison Co. v. FERC*,[55] recognized that, in the context of determining ROE, not every ROE within the DCF zone of reasonableness is just and reasonable. In that case, the utility filed to modify its rates under FPA section 205. The court stated that section 205 required the Commission to approve the utility's rate proposal "as long as the new rates are just and reasonable."[56] Nevertheless, the court also held that the Commission had authority to require the utility's ROE to be set at the median of the zone of reasonableness, even though the midpoint of the zone, proposed by the utility, was also within the DCF zone of reasonableness. In short, the court recognized that the Commission need not treat every ROE within the zone of reasonableness as a just and reasonable ROE. If the Commission were required to find any and every ROE within the zone of reasonableness to be just and reasonable, the requirement that the Commission approve any section 205 rate proposal "as long as the new rates are just and reasonable"[57] would require the Commission to accept any ROE proposed by a utility in a section 205 rate case, as long as that ROE did not exceed the top of the range of reasonableness. However, the FPA has never been understood to require such a result, which would be contrary to the consumer protection purpose of the FPA.[58]

27. In Opinion No. 531, the Commission stated that the NETOs were erroneously seeking to apply a different just and reasonable standard in FPA section 206 cases than in section 205 cases. The Commission stated, "Despite the fact FPA section 205 does not require that every ROE within the zone of reasonableness be considered just and reasonable for purposes of a utility rate filing under FPA section 205, the NETOs would

---

[55] *S. Cal. Edison Co. v. FERC*, 717 F.3d 177, 181-82 (D.C. Cir. 2013) (finding that the Commission had authority to set a utility's ROE at the median of the zone of reasonableness even though the utility proposed using the midpoint, which was also within the zone of reasonableness); *accord Montana-Dakota*, 341 U.S. at 251 (explaining that while statutory reasonableness is an abstract concept represented by an area rather than a pinpoint the Commission must translate that concept into a concrete rate, and it is the rate—not the abstract concept—that governs the rights of the buyer and seller).

[56] *S. Cal. Edison Co. v. FERC*, 717 F.3d at 181.

[57] *Wis. Pub. Power, Inc. v. FERC*, 493 F.3d 239, 254 (D.C. Cir. 2007).

[58] Given that the FPA was intended to be a consumer-protection statute, *see, e.g.*, *Pub. Sys. v. FERC*, 606 F.2d 973, 979 n.27 (D.C. Cir. 1979), it is hard to find persuasive an argument that would allow, under FPA section 205, a utility to propose an increase in its ROE to anywhere in the zone, but would effectively bar, under FPA section 206, a customer from seeking to decrease the ROE being challenged merely because the ROE falls somewhere within the zone.

require us to treat every existing ROE within the zone of reasonableness as just and reasonable in a section 206 case. Nothing in the FPA, however, supports such a different understanding of the phrase "just and reasonable" as between those two sections of the FPA when establishing a utility's ROE."

28. On rehearing, the NETOs do not challenge Opinion No. 531's interpretation of FPA section 205 as not requiring the Commission to treat any ROE proposed by the utility within the DCF zone of reasonableness as a just and reasonable ROE which the Commission must accept. However, the NETOs contend that Opinion No. 531 fails to recognize that the Commission's burden of proof under FPA section 206 contains two prongs: first, the burden to show that an existing rate is unjust and unreasonable; second, the burden to show that the replacement rate is just and reasonable. The NETOs agree that the showing the Commission must make under the second prong of section 206 in order to establish a replacement ROE "is identical to the required section 205 showing, as Opinion No. 531 states."[59] However, they assert that the showing of unjustness and unreasonableness which the Commission must make under the first prong of its section 206 burden "is very different from and more difficult to satisfy" than the showing of justness and reasonableness that must be made under either the second prong of section 206 or under section 205. As a result they assert that any ROE within the zone of reasonableness cannot be found unjust and unreasonable.

29. In making these arguments, the NETOs are confusing differences in who bears the burden of persuasion as between FPA sections 205 and 206 with the substantive "just and reasonable" standard contained in both those sections. The two sections of course differ as to who bears the burden of persuasion, because under FPA section 206 the Commission or complainant must show that the utility's existing rate is unjust and unreasonable and the Commission must show that its replacement rate is just and reasonable, whereas under FPA section 205 the utility need only show that its proposed rate is just and reasonable. However, as the Supreme Court has stated, sections 205 and 206 are "parts of a single statutory scheme under which . . . all rates are subject to being modified by the Commission upon a finding that they are unlawful."[60] While the party bearing the burden of persuasion is different under FPA section 205 and FPA

[59] NETOs Request for Rehearing at 35.

[60] *United Gas Pipe Line Co. v. Mobile Gas Serv. Co.*, 350 U.S. 332, 341 (1956). While this case involved the Natural Gas Act, the Supreme Court held in a companion case that the provisions of the FPA relevant to this question are substantially identical to the equivalent sections under the Natural Gas Act. *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 353 (1956).

section 206, "the scope and purpose of the Commission's review remains the same – to determine whether the rate fixed by the [utility] is lawful."[61]

30. Because sections 205 and 206 are part of a single statutory scheme, it follows that a rate that is lawful under one section must also be lawful under the other and a rate that is unlawful under one section must also be unlawful under the other. For this to be true, the substantive standard to determine lawfulness under each section – the just and reasonable standard – must be applied in the same manner under each section. Therefore, if every ROE within the DCF zone of reasonableness must be treated as a lawful just and reasonable ROE which cannot be modified under the first prong of the Commission's FPA section 206 burden, as the NETOs contend, then every ROE within that zone must also be treated as a lawful just and reasonable ROE for all other purposes under the FPA, including a section 205 filing. This would require the Commission to find just and reasonable any ROE proposed by a utility in a section 205 proceeding that was within the DCF zone of reasonableness. However, as already discussed, the D.C. Circuit rejected that proposition in *SoCal Edison*.

31. The NETOs next contend that failing to treat all ROEs within the DCF zone of reasonableness as just and reasonable for purposes of the first prong of the Commission's 206 burden would erase the difference between the burden of proof under FPA sections 205 and 206, because the ROE determination in a section 206 proceeding would be the same as in a section 205 proceeding. We disagree. We recognize that in situations where the Commission has found that more than one methodology may be used to design a just and reasonable rate for a service, such as the incremental rate situation in *City of Winnfield* discussed above, the utility may choose one of the just and reasonable ratemaking methodologies in a section 205 proceeding, and the Commission then cannot require the utility to shift to a different just and reasonable methodology in a subsequent

[61] *United Gas Pipe Line Co. v. Mobile Gas Serv. Co.*, 350 U.S. at 341. The effect of the NETOs' argument, if that argument were to be accepted, would turn the statute on its head. Section 206 would no longer be a tool to challenge an ROE that was no longer reasonable, but rather would serve to insulate that ROE from challenge as long as it fell somewhere—anywhere—within the zone of reasonableness produced by a DCF analysis. A statute that was intended to protect ratepayers from exploitation, *see, e.g.*, *Pub. Sys. v. FERC*, 606 F.2d at 979 n.27, would protect and preserve just such exploitation. But, as the Commission has recognized, as recently as last year the D.C. Circuit has already rejected just such an approach. *See* Opinion No. 531, 147 FERC ¶ 61,234 at P 52 (citing *S. Cal. Edison Co. v. FERC*, 717 F.3d 177).

section 206 proceeding.[62] However, the statute does not require that we approve multiple just and reasonable methodologies to resolve every ratemaking issue. In fact, the D.C. Circuit held in *S. Cal. Edison Co.* that the Commission may require the use of a particular methodology to determine the just and reasonable ROE to be included in a utility's cost of service, despite the existence of other possible methodologies for determining ROE.[63]

32. The Commission has long required the use of a DCF methodology (here the two-step DCF methodology adopted in Opinion No. 531) to determine a zone of reasonableness, with the lawful just and reasonable ROE set at a single numerical point within that range based on the circumstances and record of that case.[64] Therefore, when the Commission finds a utility's base ROE to be just and reasonable in a particular case, it finds *only* that single point to be just and reasonable given the facts and circumstances of that case.[65] It does *not* find any other base ROE within the DCF zone of reasonableness, either above or below the approved ROE, to be a just and reasonable base ROE for that utility or group of utilities. Thus, the DCF zone of reasonableness does not establish a continuum of just and reasonable base ROEs, any one of which the utility would equally be free to charge to ratepayers; rather, only the single point approved by the Commission within the DCF zone of reasonableness is the just and reasonable base

---

[62] *See Consolidated Edison of New York, Inc. v. FERC*, 165 F.3d 992, 216-17 (D.C. Cir. 1999). ("While incremental treatment may be required at one end of the rate-setting continuum, and rolled-in pricing required at the other, in between the two extremes lie a series of intermediate points in which both cost-recovery methods would satisfy section 4's just and reasonable test. At each of these places along the continuum, the pricing mechanism will essentially lie in the hands of the initiating pipeline. It is only when the proposed rate crosses the boundary separating the just from the unjust that FERC can act under its section 5 authority to order a rate of its own formulation.")

[63] *S. Cal. Edison Co. v. FERC*, 717 F.3d at 182 ("In order to discharge its statutory duty of ensuring that '[a]ll rates . . . [are] just and reasonable' the Commission may require the use of a particular ratemaking methodology so long as its embrace of that methodology is not arbitrary and capricious.").

[64] *See, e.g., Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d 54, 57 (D.C. Cir. 1999).

[65] *Cf. Montana-Dakota*, 341 U.S. at 251 (explaining that while statutory reasonableness is an abstract concept represented by an area rather than a pinpoint the Commission must translate that concept into a concrete rate, and it is the rate—not the abstract concept—that governs the rights of the buyer and seller).

ROE.[66] It follows that showing the existing base ROE established in the prior case is unjust and unreasonable merely requires showing that the Commission's ROE methodology now produces a numerical value below the existing numerical value. Contrary to the NETOs' assertion, the fact that both of the burdens of proof under FPA section 206 can be satisfied using a single ROE analysis—one that generates an ROE that both is below the existing ROE (thus demonstrating that the existing ROE is excessive) and that also is a just and reasonable ROE (thus demonstrating what the new ROE should be)—does not alter those two burdens.[67]

33. In short, the statute does not require that we treat all ROEs within the DCF zone of reasonableness as just and reasonable. Rather, the statute requires that, under section 206, before we may change an ROE we must find it unjust and unreasonable. And, in Opinion No. 531, that we did. Our ROE analysis showing that the NETOs' base ROE is 10.57 percent demonstrates both that their existing 11.14 percent ROE is unjust and unreasonable and that 10.57 percent is the NETOs' just and reasonable replacement base ROE.[68] Thus, we met both burdens under section 206.

34. The NETOs cite precedent that, while correctly stating the general principle of the FPA section 206 burden, is distinguishable from the facts of this case because that precedent did not discuss the FPA section 206 burden in the context of determining a utility's base ROE.[69] Whether a particular rate is just and reasonable, and what the range

---

[66] As discussed below in P 35, the addition of an incentive adder for a project can justify a higher overall just and reasonable ROE (i.e., the base ROE plus the incentive adder) for that project.

[67] Further, we reject the NETOs' contention that the Commission's determination on the burden of proof in this proceeding broadens the Commission's discretion and will lead to increased uncertainty and litigation. *See* NETOs Request for Rehearing at 45-46. We are following our long-standing practice with regard to the zone of reasonableness identified by a DCF analysis.

[68] A utility's ROE is simply one component of the cost-of-service reflected in its overall rates for the services it provides. Typically, each component of the cost of service is a single number, based on the utility's actual costs during the relevant test period. For example, if a utility's existing cost of service includes a cost of labor of $10 million, a showing that its actual test period cost of labor is $9 million satisfies both the burden to show that the existing $10 million labor cost is unjustly and unreasonably high and the new just and reasonable labor cost is $9 million. Our treatment of ROE is no different.

[69] *See, e.g., Maine PUC*, 520 F.3d 464, *rev'd in part on other grounds sub nom. NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 558 U.S. 165 (2010) (upholding Commission determination that transition payments agreed to in a settlement redesigning

(continued…)

of reasonableness is for that rate, largely depends on the nature of the rate at issue. While a utility's base ROE is a single, specific numerical value that is determined by using a well-known methodology, a tariff provision setting forth an energy market rule might produce a numerical result only in conjunction with many other associated market rules. A determination of what is an appropriate range of reasonableness, and what is just and reasonable, in these two disparate contexts requires different analyses and the balancing of different interests. As a result, the Commission uses different approaches to determining the just and reasonable resolution in different circumstances. In determining a utility's base ROE, the Commission has long used a methodology that produces a single, specific numerical value, not a range of reasonable values, and the Commission has therefore interpreted FPA section 206 to protect that specific numerical value, rather than a zone around that value.

35. The NETOs are correct that, in the context of incentive ROE adders authorized for projects, the Commission has capped the overall ROE for a particular project (i.e., the sum of the utility's base ROE and the incentive ROE adder for that project) at the top of the DCF zone of reasonableness.[70] However, it does not follow from this fact that all ROEs within the DCF zone of reasonableness must be treated as just and reasonable for purposes of the first prong of FPA section 206. The Commission awards an incentive adder based on a separate, independent showing that a particular project is of a type that qualifies for such an adder, and—as directed by Congress—the Commission allows the adder to be added to the base ROE and charged to ratepayers so long as the sum of the

---

New England's capacity market fell within a reasonable range of capacity prices); *Calpine Corp. v. Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,271 (finding tariff provisions setting forth a method of socializing the costs of a market participant's financial default to be unjust and unreasonable); *Cal. Mun. Utils. Ass'n v. Cal. Indep. Sys. Operator Corp.*, 126 FERC ¶ 61,315 (2009) (finding that complainants failed to show tariff unjust and unreasonable due to a lack of sufficient safeguards to protect against the risk of anomalous settlements); *Cal. Indep. Sys. Operator Corp.*, 140 FERC ¶ 61,168 (2012) (finding tariff provisions concerning the repayment of an interconnection customers' network upgrade costs to be just and reasonable under FPA section 205).

[70] *See, e.g.*, *Northeast Utils. Serv. Co.*, 124 FERC ¶ 61,044, at P 71 (2008); *Central Maine Power Co.*, 125 FERC ¶ 61,079, at P 74 (2008); *Desert Southwest Power, LLC*, 135 FERC ¶ 61,143, at P 96 (2011). The Commission uses the DCF zone of reasonableness in the same manner to ensure that the sum of a utility's base ROE plus an incentive adder for joining an RTO is just and reasonable.

adder and base ROE for that project is just and reasonable under FPA section 205.[71] The Commission makes that determination by looking at whether the utility's base ROE plus the incentive ROE adder for that project remain within the zone of reasonableness. That is, the Commission looks to whether the sum of the base ROE and the adder for that project falls within the DCF-determined zone of reasonableness, or does that sum instead fall outside the zone of reasonableness, for that project. Absent both a showing that the particular project qualifies for such an adder, and a Commission finding that the resulting overall ROE satisfies the just and reasonable standard laid out in the FPA, the increased overall ROE for the project produced by summing the adder and the base ROE would not be just and reasonable.[72] This use of the DCF-determined zone of reasonableness to place an outer limit on the overall ROE that a utility may earn on a particular project does not in any way suggest that any base ROE up to the top of the DCF-determined zone of reasonableness must be treated as just and reasonable for purposes of FPA section 206. To the contrary, it is only the separate, independent finding that the project qualifies for an incentive adder that justifies increasing the overall ROE for that project to a point within the DCF-determined zone of reasonableness above the point at which the utility's base ROE is set.

2. Placement of the Base ROE within the Zone of Reasonableness

a. Placement of the Base ROE above the Midpoint

i. Opinion No. 531

36. The Commission in Opinion No. 531 found that, although it typically sets the base ROE for a group of utilities at the midpoint of the zone of reasonableness identified by the DCF methodology, "a mechanical application of the DCF methodology with the use of the midpoint here would result in an ROE that does not satisfy the requirements of *Hope* and *Bluefield*."[73] Therefore, the Commission explained that, "based on the record in this case, including the unusual capital market conditions present, . . . the just and reasonable base ROE for the NETOs should be set halfway between the midpoint of the zone of reasonableness and the top of the zone of reasonableness," i.e., 10.57 percent.[74]

[71] *See* 16 U.S.C. § 824s(d) (2012) ("All rates approved under the rules adopted pursuant to [FPA section 219] . . . are subject to the requirements of sections [205 and 206] of this title that all rates . . . be just and reasonable.").

[72] *See generally, e.g., NSTAR Elec. Co.,* 125 FERC ¶ 61,313 (2008); *Northeast Utils. Serv. Co.*, 124 FERC ¶ 61,044 (2008).

[73] Opinion No. 531, 147 FERC ¶ 61,234 at P 142.

[74] *Id.*

The Commission explained that, as "[p]arties on both sides of the instant ROE issue argue that the unique capital market conditions have impacted the level of equity return the NETOs' require to meet the capital attraction standards of *Hope* and *Bluefield*," the Commission was "concerned that capital market conditions in the record are anomalous, thereby making it more difficult to determine the return necessary for public utilities to attract capital."[75] The Commission explained that "[i]n these circumstances, we have less confidence that the midpoint of the zone of reasonableness established in this proceeding accurately reflects the equity returns necessary to meet the *Hope* and *Bluefield* capital attraction standards."[76]

37. As a result of the anomalous capital market conditions reflected in the record, and their potential impact on the DCF model, the Commission found it "necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark methodologies and state commission-approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the [midpoint of the zone of reasonableness identified by the DCF methodology]."[77] The Commission found the additional record evidence—specifically the NETOs' risk premium analysis, Capital Asset Pricing Model (CAPM) analysis, expected earnings analysis, and evidence of state commission-authorized ROEs—supported a finding that an upward adjustment from the midpoint was warranted.[78]

38. After determining that the just and reasonable base ROE for the NETOs was above the midpoint, the Commission found that, because it "has traditionally looked to the central tendency to identify the appropriate return within the zone of reasonableness," it is appropriate to "look to the central tendency for the top half of the zone of reasonableness."[79] The Commission explained that "[w]hen placing a base ROE above the central tendency of the zone of reasonableness, the Commission has in the past placed the base ROE at the midpoint of the upper half of the zone."[80] The Commission therefore

---

[75] *Id.* P 145.

[76] *Id.*

[77] *Id.*

[78] *Id.* PP 146-150.

[79] *Id.* P 151.

[80] *Id.* P 152 (citing *S. Cal. Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070, at 61,266 (2000); *Consumers Energy Co.*, Opinion No. 429, 85 FERC ¶ 61,100, at 61,363-64 (1998)).

found that "a base ROE halfway between the midpoint of the zone of reasonableness and the top of that zone represents a just and reasonable ROE for the NETOs."[81]

ii. Requests for Rehearing

39. Petitioners and EMCOS argue that the Commission's placement of the NETOs' base ROE three-quarters of the way up the zone of reasonableness is contrary to record evidence and Commission precedent, and is therefore arbitrary and capricious. Petitioners assert that the only basis for establishing a base ROE above the central tendency of the zone of reasonableness is that the utility or utilities whose base ROE is at issue are riskier than the proxy group. Petitioners argue that the Commission's 38-member national proxy group is far more risky than the NETOs because the average corporate credit rating of the proxy group was between BBB and BBB+, whereas 80 percent of the NETOs are rated between BBB and A.[82] Petitioners further state that, using the appropriate weighting to reflect the relative size of each of the NETOs, the fair average of the NETOs' credit ratings is "A-/BBB+." Petitioners therefore argue that the Commission should place the NETOs' base ROE in the lower half of the zone of reasonableness.[83]

40. EMCOS assert that the Commission has previously and consistently concluded that the midpoint of the zone of reasonableness produces a just and reasonable ROE for a diverse group of utilities because it fairly and accurately evaluates risk. EMCOS further state that Opinion No. 531 acknowledges that the midpoint of the zone of reasonableness yields an appropriate ROE for a diverse group of utilities, but then rejects the use of the 9.39 percent midpoint in favor of the higher 10.57 percent figure.[84] EMCOS state that Opinion No. 531 cites only two cases in which the Commission adopted an ROE at the midpoint of the upper half of the zone of reasonableness, and in each of those cases the utility at issue had a higher risk profile than the proxy group.[85] Petitioners and EMCOS

---

[81] *Id.*

[82] Petitioners Request for Rehearing 16-18.

[83] *Id.* at 19 (citing Ex. SC-207). Petitioners also cite several other sources claiming that the NETOs have a high level of rate certainty.

[84] EMCOS Request for Rehearing at 10 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 142).

[85] *Id.* at 13-14 (citing *Consumers Energy Co*., 85 FERC ¶ 61,100; *S. Cal. Edison Co*., 88 FERC ¶ 61,254 (1999)).

argue that those two cases resulted in upward adjustments of 18 and 58 basis points, compared to the 118 basis point increase in this proceeding.[86]

41. EMCOS state that Opinion No. 531 rejects the use of the midpoint of the zone of reasonableness asserting that capital market conditions here are "unique" and "anomalous." EMCOS state that the ROE awarded must reflect the capital market conditions under which the NETOs operate and that Commission precedent recognizes the importance of basing an ROE on current market data.[87] Petitioners and EMCOS state that Opinion No. 531 asserts it must adopt an ROE higher than the midpoint because *Hope* and *Bluefield* require the Commission to identify an ROE that will attract sufficient capital; however, this position fails to recognize that market conditions must be reflected in an ROE in order for it to be just and reasonable. EMCOS explain that they made this argument in their Initial Brief, and that Opinion No. 531 acknowledged it, but did not provide any explanation of why it does not apply here.[88] EMCOS argue that this case covers "the Great Recession" which had an effect on all companies and consumers, but Opinion No. 531's decision to upwardly adjust the base ROE in this proceeding uniquely shields the NETOs from the economic realities of that time period at the expense of New England consumers.[89]

42. Petitioners state that Opinion No. 531's reliance on a single issuance from UBS Financial Services (UBS) included in the testimony of the NETOs' witness, Ms. Lapson, is neither well-founded nor consistent with the record. Petitioners also state that the reports in Ms. Lapson's testimony were not selected by her, but were hand-picked by the NETOs' counsel and that the testimony includes almost nothing addressing the views of specific investment analysts as to the potential impact of an ROE reduction in this proceeding on future transmission investment. Petitioners further argue that, a few months after the UBS report, UBS changed its mind and stated that the outcome of this proceeding "impacts only the generic New England rates." Petitioners explain that there were many different views taken by other analysts which were unrebutted, which they state explains why there is no well-founded basis for a concern that a base ROE reduction

[86] *Id.* at 14-15.

[87] *Id.* at 16-17 (citing *Portland Natural Gas Transmission Sys*., Opinion No. 510-A, 142 FERC ¶ 61,198, at P 233 (2013); *Consumer Advocate Div. of the Pub. Serv. Comm'n of West Virginia v. Allegheny Generating Co*., 68 FERC ¶ 61,207, at 61,998 (1994) (*West Virginia Consumer Advocate*)).

[88] *Id.* at 17-18 (citing *Bluefield*, 262 U.S. at 692; *Hope*, 320 U.S. at 614).

[89] *Id.* at 19.

to the central result of the national proxy group could undermine the NETOs' ability to attract capital.[90]

43. Petitioners and EMCOS also assert that the Commission erred in relying on certain record evidence—i.e., the evidence of state commission-authorized ROEs and the NETOs' alternative methodologies for estimating the cost of equity—to corroborate the placement of the base ROE within the zone of reasonableness. Petitioners and EMCOS argue that, in relying on these alternative methodologies, Opinion No. 531 departed from Commission precedent without providing an explanation for doing so. Petitioners contend that the Commission has repeatedly found that non-DCF approaches to determining transmission ROEs are "unlikely to produce a just and reasonable result."[91] For example, Petitioners contend that, in the case that recently concluded with the D.C. Circuit affirming the Commission's sole reliance on the electric utility DCF median, Southern California Edison Company had sought to bolster its case for a high ROE by relying on the CAPM analysis.[92] Petitioners note that the Commission refrained from according the non-DCF analyses even the little weight sought by Southern California Edison Company. Petitioners argue that the use of the NETOs' alternative methodologies should have been subject to the well-established test for an above-center ROE: no upward movement should be undertaken unless those methodologies make "a very persuasive case" that the central result of a conventional DCF study fails to identify the subject utility's true equity cost.[93] Petitioners contend that the Commission failed to state a reasoned basis for not applying the "very persuasive case" standard.

44. Petitioners and EMCOS further argue that the Commission's reliance on the NETOs' alternative benchmark methodologies without scrutinizing their flaws is inconsistent with reasoned decision-making and constitutes judicially-reversible error.[94] Petitioners and EMCOS also argue that the Commission's DCF analysis contains certain

---

[90] Petitioners Request for Rehearing 53-57.

[91] *Id.* at 30 (citing *Xcel Energy Servs., Inc.*, 122 FERC ¶ 61,098 at P 73, *clarified*, 125 FERC ¶ 61,092 (2008) (*Xcel*)).

[92] *Id.* at 30-31 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020, at P 114 (2010) (*SoCal Edison*), *reh'g denied*, 137 FERC ¶ 61,016 (2011), *petition for review granted in part and denied in part*, *S. Cal. Edison Co. v. FERC*, 717 F.3d 177).

[93] *Id.* at 32.

[94] *Id.*; EMCOS Request for Rehearing at 20 (citing *Ill. Pub. Telecomm. Ass'n v. FCC*, 117 F.3d 555, 564 (D.C. Cir. 1997)).

flaws that undermine the Commission's decision to place the base ROE above the midpoint of the zone of reasonableness.

45. Petitioners' and EMCOS's arguments as to the specific, alleged flaws in both the Commission's DCF analysis and the record evidence on which the Commission relied to corroborate the placement of the base ROE above the midpoint are described below.

iii. Commission Determination

46. We deny rehearing on the issue of where to place the NETOs' base ROE within the zone of reasonableness produced by the Commission's DCF analysis.

47. As an initial matter, we disagree with Petitioners' and EMCOS's arguments concerning the circumstances under which the Commission may set a base ROE at a point other than the central tendency of the zone of reasonableness.[95] Petitioners assert that the Commission may only do so by comparing the NETOs' risks to the risks of the proxy group produced by the DCF methodology—i.e., by conducting a comparison that the Commission has historically referred to as the "relative risk analysis." We disagree. In this case, the Commission found the proxy group to be comparable in risk to the NETOs,[96] but determined that it was necessary to adjust the NETOs' base ROE above the midpoint based on considerations other than the relative risk analysis.[97] While the Commission has indeed adjusted a company's base ROE above or below the central

---

[95] We also disagree with Petitioners' argument that the two precedents the Commission cited in support of using the midpoint of the upper half of the DCF-produced zone of reasonableness are distinguishable from the instant case because the upward adjustments in those two cases—*S. Cal. Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070, and *Consumers Energy Co.*, Opinion No. 429, 85 FERC ¶ 61,100—were of 58 and 18 basis points, respectively, compared to the 118 basis adjustment in Opinion No. 531. Nothing in those cases indicates that the Commission made those adjustments because they were for 58 or 18 basis points. Instead, the Commission in Opinion Nos. 445 and 429 placed the ROE at the midpoint of the upper half of the zone after finding that an upward adjustment was warranted, which is what the Commission did in Opinion No. 531.

[96] *See* Opinion No. 531, 147 FERC ¶ 61,234 at P 96.

[97] *Id.* PP 144-145.

tendency of the zone or reasonableness based on the relative risk analysis,[98] the Commission is not limited to making adjustments based only on the relative risk analysis. Petitioners' argument to the contrary is inconsistent with both court and Commission precedent showing that the Commission has the discretion to make,[99] and has in fact made, adjustments to a rate based on the particular circumstances of a case, including whether unique circumstances render the results of the Commission's DCF analysis less reliable than usual.[100]

48. We disagree with Petitioners' argument that the NETOs' are less risky than the proxy group. While Petitioners assert that 80 percent of the NETOs' have credit ratings between BBB to A, whereas the average credit rating of the proxy group company is between BBB and BBB+, this alone does not show that the NETOs are less risky than the proxy group. As explained in Opinion No. 531, the Commission uses the credit rating band because it "include[s] in the proxy group only those companies whose credit ratings *approximate* those of the utilities whose rates are at issue."[101] We thus reiterate that Commission's finding that the credit rating band of the proxy group is comparable to the NETOs' credit ratings.[102] Further, Petitioners' argument is based on a flawed comparison of the two groups' credit ratings. Assuming *arguendo* that it is helpful to compare the distribution of the NETOs' credit ratings to the average credit rating of proxy group companies, that analysis should be accompanied by a comparison of how the distribution of the proxy group companies' credit ratings compare to the average credit rating of the proxy group. In other words, the distribution of the NETOs' credit ratings should be compared to the distribution of the proxy companies' credit ratings. Petitioners' comparison is misleading because it fails to do this. In this case 34 of the 38

---

[98] *See, e.g., Williston Basin Interstate Pipeline Co. v. FERC*, 165 F.3d at 57 ("Once the Commission has defined a zone of reasonableness [using the DCF model], it then assigns the pipeline a rate within that range to reflect specific investment risks associated with that pipeline as compared to the proxy group companies.").

[99] *See, e.g., Fed. Power Comm'n v. Natural Gas Pipeline Co.*, 315 U.S. 575, 586 (1942) ("The Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas. Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.")

[100] *See, e.g.*, *Town of Norwood*, *Mass. v. FERC*, 80 F.3d 526, 534-535 (D.C. Cir. 1996).

[101] Opinion No. 531, 147 FERC ¶ 61,234 at P 106 (emphasis added).

[102] *See id.* P 108.

companies in the proxy group—i.e., 89 percent of the proxy companies—have credit ratings between BBB and A, compared to the 80 percent of the NETOs within that band.[103] This indicates that the credit ratings of the proxy group companies and the NETOs are similarly distributed, and supports a finding that the two groups have comparable risk profiles.

49. Petitioners and EMCOS argue that the Commission erred in basing its decision to set the NETOs' base ROE above the central tendency of the zone of reasonableness produced by the DCF analysis on the presence of anomalous capital market conditions. Petitioners specifically argue that the slow economic growth reflected in the record is not anomalous, but is instead a "new normal" and should, therefore, not justify adjusting the base ROE above the midpoint. We are not persuaded by Petitioners' argument. In Opinion No. 531, the Commission acknowledged that parties on both sides of the issue had cited to unique capital market conditions.[104] The Commission also referenced U.S. Treasury bond yields, not economic growth, as an indicator of current capital market conditions. Given the undisputed presence of such anomalous capital market conditions, the Commission stated that it had "less confidence that the midpoint of the zone of reasonableness established in this proceeding accurately reflects the equity returns necessary to meet the *Hope* and *Bluefield* capital attraction standards."[105] However, we did not stop there in our analysis of whether it was appropriate to establish a base ROE above the midpoint. Rather, the record evidence of unusual capital market conditions served as an impetus for the Commission's consideration of additional record evidence. This consideration was necessary to evaluate, in this proceeding, whether setting the NETOs' ROE at the midpoint of the zone of reasonableness satisfied the requirements of *Hope* and *Bluefield*. Therefore, the Commission conducted a further analysis by analyzing the additional record evidence, including evidence of alternative benchmark methodologies and state commission-approved ROEs, to gain insight into the potential impacts of the unusual capital market conditions on the appropriateness of using the resulting midpoint. We then used this additional record evidence to corroborate our determination that placement at a point above the midpoint was warranted.[106]

50. We also reject EMCOS's argument that, even if the capital market conditions reflected in the record are anomalous, adjusting the NETOs' ROE based on an economic anomaly ignores the *Hope* and *Bluefield* requirement that a utility's ROE must reflect

[103] *See* Ex. NET-701.

[104] Opinion No. 531, 147 FERC ¶ 61,234 at P 145.

[105] *Id.*

[106] *Id.* PP 146-149.

current market conditions. EMCOS specifically argue that whether capital market conditions in the record are anomalous from a historical perspective is irrelevant to the determination of a just and reasonable base ROE, because the base ROE must reflect the capital market conditions under which the NETOs operate, even if those conditions are historically anomalous. We disagree. The EMCOS's argument assumes that DCF analyses are immune to ever being skewed by economic anomalies. This assumption is unrealistic, as all methods of estimating the cost of equity are susceptible to error when the assumptions underlying them are anomalous.[107] The Commission, in fact, acknowledged this limitation in Opinion No. 531,[108] and was concerned that a mechanical application of the two-step DCF methodology with the use of the midpoint in such circumstances would produce a return that would not satisfy the requirements of *Hope* and *Bluefield*.[109] Therefore, based on the presence of anomalous capital market conditions, the Commission considered additional record evidence that supported an upward adjustment. Contrary to EMCOS's assertions, the Commission is not constrained to a mechanical application of the DCF methodology where the Commission determines that such an approach will not produce a just and reasonable result.[110] We further reject

---

[107] Roger A. Morin, New Regulatory Finance 28 (Public Utilities Reports, Inc. 2006) ("For instance, by relying solely on the DCF model at a time when the fundamental assumptions underlying the DCF model are tenuous, a regulatory body greatly limits its flexibility and increases the risk of authorizing unreasonable rates of return. The same is true for any one specific model."). We note that participants on both sides of the instant ROE issue in this proceeding have relied upon Dr. Morin's New Regulatory Finance. *See*, *e.g.*, Ex. S-1 at 59-60 (Trial Staff exhibit quoting New Regulatory Finance); Ex. NET-300 at 67 (NETOs exhibit quoting New Regulatory Finance); Tr. 580-581 (Complainants' cross-examination relying on New Regulatory Finance).

[108] Opinion No. 531, 147 FERC ¶ 61,234 at PP 41, 145.

[109] *Id.* PP 150-152.

[110] *See Fed. Power Comm'n v. Natural Gas Pipeline Co.*, 315 U.S. at 586 ("The Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas. Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.").

We note that neither of the Commission precedents to which Complainants cite in support of their argument—*Portland Nat. Gas Transmission Sys.*, Opinion No. 510-A, 142 FERC ¶ 61,198 (2013) (Opinion No. 510-A) and *West Virginia Consumer Advocate*, 68 FERC ¶ 61,207—constrain the Commission to mechanically apply a particular ratemaking approach without regard to economic anomalies. *West Virginia Consumer*

(continued…)

EMCOS's argument that this analysis should be affected by the fact that the NETOs can subsequently request a rate increase under FPA section 205. The NETOs' ability to subsequently request a rate increase if economic conditions change does not excuse the Commission from establishing an ROE under FPA section 206 that meets the requirements of *Hope* and *Bluefield*.

51. Petitioners argue that the Commission erred in finding that a base ROE of 9.39 percent could undermine the NETOs' ability to attract capital for new investment, because the finding was based on only one analyst's report, from UBS, which is contradicted by record evidence of other analysts' reports. We disagree. Petitioners specifically cite analysts' reports from Credit Suisse; Goldman Sachs; Brean Murray, Carret & Co. (Brean Murray); Deutsche Bank; and a subsequent report from UBS. But none of the reports Petitioners cite contradicts the finding that a base ROE of 9.39 percent—i.e., a reduction of 175 basis points from the existing base ROE—could undermine the NETOs' ability to attract capital.[111]

52. The Deutsche Bank report and the subsequent report from UBS provide no analysis of how a reduced base ROE would impact the NETOs and, therefore, do not contradict the UBS report the Commission relied upon in Opinion No. 531. The Deutsche Bank report merely states the possibility that the Commission could reduce the

---

Advocate did not involve any unusual capital market conditions. *See generally West Virginia Consumer Advocate*, 68 FERC ¶ 61,207. While Opinion No. 510-A did involve allegations of economic anomalies, the Commission in that case, in fact, weighed the evidence of anomalous conditions in determining whether to apply its policy of using the most recent record data or to use an alternative data set. *See* Opinion No. 510-A, 142 FERC ¶ 61,198 at P 233. Thus, Opinion No. 510-A demonstrates that the Commission may indeed consider, as it has here in Opinion No. 531, whether to apply or adjust an established policy based on anomalous economic conditions.

[111] We also reject Petitioners' argument that the NETOs' expert witness was not qualified to present testimony on this issue. The NETOs' expert witness has 43 years of experience as a financial professional, including 38 years focused on financial analysis and securities evaluation within the utilities sector, and was formerly the Managing Director of the utilities, power, and gas analytical team at Fitch Ratings, where she "supervised and wrote the credit rating criteria applied in the electric, gas, and water sector." Ex. NET-400 at 1-3.

The Presiding Judge, furthermore, admitted this witness's testimony into the record and found it "to have moderate probative value." S*ee* Initial Decision, 144 FERC ¶ 63,012 at P 576; *Entergy Servs., Inc.*, 109 FERC ¶ 61,108, at P 7 (2004) (citing 18 C.F.R. § 385.209 (2004)).

NETOs' base ROE as a result of the low interest rate environment, while the later UBS report describes the scope of the proceeding and predicts a general trend of lower ROEs for regulated utilities, without discussing the magnitude of the potential ROE reductions or their impact on utilities' ability to attract capital.

53. The reports from Credit Suisse, Goldman Sachs, and Brean Murray provide limited analysis of two holding companies that are parent companies to certain NETOs, and none of that analysis undermines the UBS report the Commission cited in Opinion No. 531. The Credit Suisse report states that a 50 to 100 basis point reduction in Northeast Utilities' ROE in this proceeding would be a "positive" for the company.[112] This statement, which we interpret to mean simply that a reduction of 50 to 100 basis points would be better for Northeast Utilities than would an even greater reduction, is silent on the impacts that a reduced ROE would have on Northeast Utilities' ability to attract capital. The Goldman Sachs report, which also only addresses Northeast Utilities, states that a 100 basis point reduction to Northeast Utilities' ROE would have a minimal impact on Northeast Utilities' earnings per share and that the impact could be overcome by adding $200-$300 million in transmission projects to Northeast Utilities' rate base. This evidence is solely focused on the impact that an ROE reduction would have on Northeast Utilities' earnings per share and, therefore, provides insufficient evidence to determine how such a reduction would impact Northeast Utilities' ability to attract capital.[113] Because the Credit Suisse and the Goldman Sachs reports only address the impact of ROE reductions of up to 100 basis points, neither is probative on the issue of how a significantly greater 175 basis point ROE reduction to 9.39 percent would affect the NETOs' ability to attract capital.

54. The Brean Murray report, which states that "[a] negative impact to [UIL Holdings] from an adverse decision would be minimal, in our view," is the least probative of these three reports. What would constitute an "adverse decision," for example, is unclear. Whether and to what magnitude an adverse ruling in this proceeding would impact the NETOs' ability to attract capital, moreover, cannot be determined with any certainty based on the magnitude of the impact the ruling might have on the much larger and more diversified parent company of one of the NETOs.

---

[112] Petitioners Request for Rehearing at 57; Ex. SC-518 at 5. We further note that the 10.57 percent base ROE established in this proceeding reduced the NETOs' base ROE by 57 basis points, which is within the 50 to 100 basis point range that Credit Suisse reported would be a positive outcome for Northeast Utilities.

[113] While a company's earnings are undeniably relevant to its ability to attract capital, it is merely one of multiple factors investors rely on in determining whether to invest in the company. For example, looking at earnings in isolation provides no information about the company's dividend yield.

55. We are also unpersuaded by Petitioners' arguments that, if the Commission concludes that the NETOs' base ROE should be set above the midpoint of the zone of reasonableness, the base ROE should be placed at the true 75th percentile of the zone of reasonableness, i.e., 9.84 percent, rather than at the 10.57 percent midpoint of the upper half of the zone. As the Commission explained in Opinion No. 531, the Commission has traditionally used measures of central tendency to determine an appropriate return in ROE cases and, in cases involving the placement of the base ROE above the central tendency of the zone of reasonableness, the Commission has used the central tendency of the top half of the zone. Our decision to utilize the midpoint of the upper half of the zone is based on the record evidence in this proceeding and is consistent with the Commission's established policy of using the midpoint of the ROEs in a proxy group when establishing a central tendency for a region-wide group of utilities.[114] Further, we reject Petitioners' assertion that *Northwest Pipeline Corp.*, 99 FERC ¶ 61,305 (2002), requires the Commission to consider the distribution of results within the proxy group when determining where in the upper half of the zone to place the NETOs' base ROE. *Northwest Pipeline Corp.* does not bear on the Commission's decision in this proceeding to place the NETOs' base ROE above the midpoint of the zone of reasonableness, as that case involved the issue of which particular measure of central tendency should be used in setting a single pipeline's ROE *at the middle* of the zone of reasonableness.[115]

56. Lastly, we disagree with Petitioners that the Commission erred in relying on the NETOs' alternative methodologies to support its decision that an upward adjustment from the midpoint was warranted in this case. While Petitioners cite *Xcel*, 122 FERC ¶ 61,098, *Pacific Gas & Electric Company*, 141 FERC ¶ 61,168 (2012) (*PG&E*), *SoCal Edison*, 131 FERC ¶ 61,020, and *ITC Holdings Corp.*, 121 FERC ¶ 61,229 (2007)

---

[114] *SoCal Edison*, 131 FERC ¶ 61,020 at P 92, *aff'd in relevant part, S. Cal. Edison Co. v. FERC*, 717 F.3d at 185-87.

[115] *Northwest Pipeline Corp.*, 99 FERC ¶ 61,305 at 62,276. The Commission typically looks to the central tendency as the "most just and reasonable" and "most appropriate" return that best considers that range, and typically uses the median as the measure of central tendency in cases involving a single utility's ROE and uses the midpoint as the measure of central tendency in cases involving the ROE for a group of utilities. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,302, at PP 9-10 (2004), *aff'd in relevant part sub nom. Pub. Serv. Comm'n of Ky. v. FERC,* 397 F.3d 1004, 1010-11 (D.C. Cir. 2005) (*PSC of Kentucky*); *SoCal Edison*, 131 FERC ¶ 61,020 at P 92, *aff'd in relevant part, S. Cal. Edison Co. v. FERC*, 717 F.3d at 185-87. *Northwest Pipeline Corp.*, in contrast, merely explains the rationale for selecting the median as the appropriate measure of central tendency in a case involving a single utility's ROE.

(*ITC Holdings*), as precedent in which the Commission has declined to rely on alternative methodologies, we find the precedent to be distinguishable from the instant case because in none of those four cases did the record contain evidence of unique capital market conditions that called into question the rote application of the midpoint of the zone of reasonableness resulting from the Commission's DCF methodology. Additionally, in *PG&E*, the Commission set the ROE issue for hearing without any reference to the reliability of the alternative methodologies the utility submitted in support of its filing.[116] Further, Petitioners are mistaken that the Commission in *SoCal Edison* did not give weight to the alternative methodologies. As the Commission in that case explained, the three alternative methodologies submitted in that case "were not used by the Commission in setting a base ROE for SoCal Edison," but "were used to corroborate the results of its DCF analysis."[117] With regard to *ITC Holdings*, as discussed below, the CAPM analysis presented in that case contained methodological shortcomings that distinguish it from the NETOs' CAPM analysis in this case.[118]

57. Petitioners and EMCOS also allege that the Commission's DCF analysis and the evidence the Commission relied upon to corroborate it contain various flaws. Those arguments are addressed in turn below.

b. Discounted Cash Flow Analysis

i. Opinion No. 531

58. In Opinion No. 531, the Commission conducted a DCF analysis using a national proxy group of companies listed as Electric Utilities by *Value Line* and that had credit ratings within one notch above or below the NETOs' credit ratings (referred to as the "credit rating screen"), had paid 6-months of dividend yields without making or announcing a dividend cut, were not involved in merger and acquisition activity significant enough to distort the DCF results, and were not low-end or high-end outliers.

59. In using the national proxy group, rather than a regional proxy group, the Commission explained that "widening the geographic range of the proxy group allows for the application of more stringent screening criteria, to refine the proxy group to a level of risk more comparable, while maintaining a group of proxy companies that is sufficiently

---

[116] *PG&E*, 141 FERC ¶ 61,168 at P 23.

[117] *SoCal Edison*, 131 FERC ¶ 61,020 at P 116. And here they were similarly used to "gain insight" and "inform" our thinking on whether an upward adjustment was reasonable. Opinion No. 531, 147 FERC ¶ 61,234 at PP 145-149.

[118] *See infra* P 115.

large and diverse to reliably capture the range of reasonable returns."[119] In applying the credit rating screen, the Commission explained that "the purpose of the credit rating band screen is to include in the proxy group only those companies whose credit ratings approximate those of the utilities whose rates are at issue."[120] The Commission found that, because investors rely on credit ratings from both Standard & Poor's (S&P) and Moody's, "basing the credit rating screen on data only from S&P does not necessarily provide an accurate estimate of the NETOs' risk."[121] Therefore, the Commission found that "in applying the credit rating proxy group screen to exclude companies more than one notch above or below the NETOs' credit ratings, it is appropriate to use both the S&P corporate credit ratings and the Moody's issuer ratings *when both are available*."[122] Because the NETOs' S&P credit ratings ranged from A- to BBB and Moody's credit ratings ranged from A2 to Baa2, the Commission excluded companies from the proxy group that were more than one notch above or below either of those credit rating bands.[123]

60. In screening the proxy groups for outliers, the Commission affirmed the Presiding Judge's application of the Commission's low-end outlier test in this proceeding, explaining that the "purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt."[124] The Commission explained that "[i]n public utility ROE cases, the Commission has used 100 basis points above the cost of debt as an approximation of this threshold, but has also considered the distribution of the proxy group companies to inform its decision on which companies are outliers."[125] The Commission explained that the cost of debt for the relevant study period was 4.61 percent and, therefore, the Commission eliminated three companies whose DCF results failed the low-end outlier test—Edison International (3.11 percent), Ameren Corp.

---

[119] Opinion No. 531, 147 FERC ¶ 61,234 at P 96.

[120] *Id.* P 106.

[121] *Id.* P 107.

[122] *Id.*

[123] *Id.* P 108.

[124] *Id.* P 121.

[125] *Id.*

(5.26 percent), and Public Service Enterprise Group Inc. (PSEG) (5.62 percent).[126] The Commission explained that PSEG's DCF result was only one basis point above the 100 basis point threshold, and that the Commission's decision to eliminate PSEG was informed by the fact that there was a 141 basis point break between PSEG's DCF result and that of the next lowest proxy group company.[127]

61. With regard to the high-end outlier test, the Commission found that "the high-end outlier issue in this proceeding is moot,"[128] explaining that "[u]nder the two-step DCF methodology, it is unnecessary to screen the proxy group for unsustainable growth rates because the methodology assumes the long-term growth rate for each company is equal to GDP." The Commission explained that, as a result, "no company in the proxy group we are adopting here has a composite growth rate under the two-step DCF methodology in excess of the 7.66 percent growth rate of PNM Resources, Inc., or an ROE in excess of the 11.74 percent ROE of UIL Holdings," which are "well within any high-end outlier test we have previously applied in utility rate cases."[129]

ii. Requests for Rehearing

62. Petitioners assert that the Commission's DCF analysis in Opinion No. 531 contained flaws that undermine the Commission's decision to place the base ROE above the midpoint of the zone of reasonableness.

63. Petitioners argue that the Commission erred in relying on a short-term growth estimate for UIL Holdings, Inc. (UIL Holdings) of 8.07 percent, which Petitioners allege was based on only one analyst estimate.[130] According to Petitioners, Commission precedent indicates that, when calculating the dividend growth rate, the Commission's analysis should be based upon as much independently calculated data as possible, and that IBES growth estimates are reliable only insofar as they represent the consensus of

---

[126] *Id.* P 123.

[127] *Id.*

[128] *Id.* P 118.

[129] *Id.*

[130] Petitioners Request for Rehearing at 48 (citing Exs. SC-313 and SC-314 (showing that 8.07 percent long-term growth projection for UIL Holdings represents the forecast of one analyst)).

multiple analysts.[131] In addition, Petitioners state that the Commission has made clear that its approval of the Yahoo! reported growth estimates that represent a consensus is not exclusive of other credible sources[132] and that comparable growth projections from other sources could be considered along with Value Line projections and what was then IBES.[133]

64. Petitioners state that it is critical in this case, and in future cases, that the Commission follow its precedent by requiring that the short-term growth rate for each proxy company be based on multiple projections. Petitioners argue that UIL Holdings's New England transmission business is smaller than its natural gas distribution business,[134] and it is therefore a less-than-ideal proxy for setting an electric transmission ROE.[135] Petitioners also assert that, during the relevant period, the Moody's credit rating for UIL Holdings was Baa3, lower than the Baa2 rating of its transmission subsidiary, United Illuminating Company, and the lowest rank among all retained proxy

---

[131] *Id.* at 45 (citing *Yankee Atomic Elec. Co.*, Opinion No. 285, 40 FERC ¶ 61,372, at 62,210 (1987) (*Yankee Atomic*), *reh'g denied*, Opinion No. 285- A, 43 FERC ¶ 61,232 (1988) (rejecting sole reliance on Zacks' predictions of earnings growth in favor of multiple data sources for projecting earnings); *Northwest Pipeline Corp.*, 87 FERC ¶ 61,266, at 62,059 (1999) (*Northwest Pipeline*) ("[t]he IBES data is a compilation of projected growth rates from various knowledgeable financial advisors with the industry.")).

[132] *Id.* at 46 (citing *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048, at PP 83-84 (2008), *reh'g dismissed*, 123 FERC ¶ 61,259 (2008) (conditionally allowing, but not requiring, reference to growth forecasts published by Yahoo!)).

[133] *Id.* (citing *ISO New England, Inc.*, 109 FERC ¶ 61,147, at P 205 (2004), *petition for review denied sub nom. Me. Pub. Utils. Comm'n v. FERC*, 454 F.3d 278 (D.C. Cir. 2006); *ISO New England, Inc.*, 110 FERC ¶ 61,111, at P 23, *reh'g denied*, 111 FERC ¶ 61,344 (2005)).

[134] *Id.* at 49.

[135] *Id.* (citing *Consumers Energy Co.*, Opinion No. 456, 98 FERC ¶ 61,333 (2002)).

companies.[136] Petitioners assert that these considerations provide reasons to avoid undue reliance on the forecasts of one analyst.[137]

65. Petitioners state that because the IBES projection for UIL Holdings was the opinion of a single analyst, Opinion No. 531 erred in failing to apply any of the other growth estimates available in the record to check whether the IBES projection for UIL Holdings produced reasonable results. Petitioners contend that neither Opinion No. 531 nor any participant identified a prior case in which the Commission placed the base ROE three-quarters of the way up the zone of reasonableness based on a high-end proxy result that was driven by the forecast of just one analyst. Petitioners state that using Value Line or Reuters data for UIL Holdings's short-term growth rate in the two-step DCF methodology provides a more appropriate benchmark than the NETOs' alternative cost of equity studies, and shows that a base ROE of 9.39 percent is sufficient for the NETOs.[138]

66. Petitioners also argue that UIL Holdings's DCF result reflects a "circularity problem" that counsels against placing the base ROE at the upper quarter of the zone of reasonableness, and instead supports placing the base ROE no higher than the true 75th percentile of the proxy group companies' DCF results. Petitioners state that the "circularity problem" is that much of UIL Holdings's dividends, earnings, and earnings growth are a result of ROE incentive adders, and UIL Holdings's DCF result reflects investors' expected revenues from those ROE incentive adders. Petitioners assert that the NETOs' base ROE should be determined exclusive of the transmission incentive revenues of the proxy group companies.

67. Petitioners also state that this circularity problem should have been mitigated by placing the base ROE closer to the true "75th percentile" of the proxy group DCF results, i.e., based on 75 percent of the 38 proxy company results (interpolated between the 28th-highest and 29th-highest results), rather than at the upper quarter of the zone of reasonableness. Petitioners state that the key difference between the actual 75th percentile and the top-quarter approach that Opinion No. 531 labels as the "75th percentile" is that the actual percentile reflects the distribution of proxy group results, whereas the Commission's top-quarter approach discards all of that information and relies on the 3:1 weighted average of the two most extreme results. Petitioners assert that discarding information on the distribution of proxy results and considering only their

---

[136] *Id.* (citing Ex. NET-600 at 9).

[137] *Id.*

[138] *Id.* at 45.

extremes is statistically indefensible and inconsistent with precedent applying Opinion No. 531's two-step DCF methodology.[139]

68. Lastly, Petitioners argue that the Commission erred in eliminating PSEG's DCF result of 5.61 percent as a low-end outlier, thereby raising the bottom of the zone of reasonableness produced by the Commission's DCF analysis. Petitioners state that this error reinforces the arguments against raising the base ROE within the zone of reasonableness. Petitioners state that Opinion No. 531 discarded PSEG's DCF result on the grounds that, although it was above the average bond yield by more than 100 basis points, it fell below a "natural break" in the proxy group's DCF results. Petitioners argue that, while Opinion No. 531 states that this rationale "buttressed" the decision to exclude PSEG, the natural break was actually the sole basis for the Commission's decision.[140]

69. Petitioners argue that the "natural break" standard must be applied evenhandedly to low-end and high-end outliers alike, but in Opinion No. 531 the Commission ignored the fact that there was a comparable "natural break" at the high end of the range of DCF results. Specifically, Petitioners assert that the 5.62 percent result for PSEG should not have been discarded unless the 11.74 percent result for UIL Holdings was also discarded.[141]

iii. <u>Commission Determination</u>

70. We deny rehearing on the various issues that Petitioners and EMCOS raise concerning the Commission's DCF analysis and their related objections to setting the base ROE above the midpoint of the zone of reasonableness.

71. Petitioners argue that the Commission erred in using UIL Holdings's DCF result to set the top of the zone of reasonableness in the Commission's DCF analysis, because UIL Holdings's DCF result was based on an IBES short-term growth projection that reflected only one analyst's growth rate projection. We reject this argument as it is contrary to years of established Commission precedent approving the use of IBES short-term growth projections in the two-step DCF methodology. For example, in *Transcontinental Gas Pipe Line Corp.*[142] the Commission rejected contentions that IBES

---

[139] *Id.* at 58-59 (citing *Northwest Pipeline Corp.*, 99 FERC ¶ 61,305).

[140] *Id.* at 60.

[141] *Id.* at 61.

[142] *Transcontinental Gas Pipe Line Corp.*, Opinion No. 414-B, 85 FERC ¶ 61,323, at 62,268-9 (1998) (Opinion No. 414-B).

growth projections should not be used in the two-step DCF methodology, because the analysts making those projections allegedly are overly optimistic in their projections. The Commission pointed to substantial evidence in the record of that case that investors rely on IBES growth projections in making investment decisions. The Commission also noted that the appropriate dividend growth rate to include in a DCF analysis is the growth rate expected by the market. While the market may be wrong in its expectations as reflected in the IBES growth projections, the cost of common equity to a regulated enterprise depends upon what the market expects, not upon precisely what is actually going to happen.

72. We recognize that the Commission has supported its use of IBES growth projections based on the fact that the IBES data is a compilation of projected growth rates from various knowledgeable financial advisors.[143] However, the Commission has not required that the IBES growth projection for each member of the proxy group reflect a minimum number of analyst growth estimates.[144] IBES, which the Commission has long relied on as the source of the growth rate projections to be used in the Commission's DCF analyses, does not publish the number of analyst estimates on which a company's growth rate estimate is based.[145] As a result, there seems little reason to conclude that investors' reliance on IBES growth projections necessarily varies depending upon the exact number of analysts contributing to any particular IBES growth projection. On balance, we find it preferable to use a consistent source of dividend growth projections for all members of the proxy group as provided by IBES, rather than to use different sources of growth projections depending upon the number of analysts contributing to each IBES growth projection, which, as discussed below, could produce skewed results. Accordingly, if a proxy company has a growth rate estimate from IBES, as does UIL Holdings, that growth rate is acceptable for purposes of the Commission's DCF analysis, regardless of the number of analysts on which it was based.

73. Contrary to Petitioners' assertion, *Yankee Atomic* and *Northwest Pipeline* do not require a different result. *Yankee Atomic* involved a much different analysis than in the instant case, because the Commission found that the small proxy group in *Yankee Atomic* was "not a valid indicator of the Yankee companies' cost of capital because the five companies are different from the Yankees in too many significant respects."[146] Because

---

[143] *Northwest Pipeline*, 87 FERC ¶ 61,266 at 62,059.

[144] *E.g.*, *SoCal Edison*, 131 FERC ¶ 61,020 at P 36.

[145] We also note that the Value Line data—which the Commission has similarly long relied upon as the source of earnings estimates in ROE proceedings—for any company consists of an earnings estimate from only one analyst.

[146] *Yankee Atomic*, 40 FERC ¶ 61,372 at 62,211.

the record did not contain a valid proxy group, the Commission had to project the Yankee Companies' dividend growth based solely on projections of those companies' own dividend growth. Therefore, the Commission determined that it should base the Yankee Companies' dividend growth projection on as many independent growth projections as possible. In contrast, this case involves a robust proxy group of companies that are comparable to the NETOs, for which dividend growth projections are available to enable the Commission to conduct a full DCF analysis. This provides the Commission a significant amount of information concerning the NETOs' cost of equity. As to *Northwest Pipeline*, in that case the Commission actually rejected the very argument on which Petitioners rely, as the Commission found that it would be inappropriate to use multiple sources of growth rate data, rather than IBES alone, in determining the short-term growth projection in the two-step DCF methodology.[147]

74. Petitioners argue that the Commission erred in placing the base ROE halfway between the midpoint of the zone of reasonableness and the top of the zone because UIL Holdings's high-end result is affected by a "circularity problem," i.e., that UIL Holdings's dividends, earnings, and earnings growth are impacted by its incentive ROE adders. The Commission has rejected this argument in the past, and we do so here for the same reasons. In Order No. 679-A, the Commission rejected the argument "that incentive ROEs will 'destabilize' the DCF methodology," explaining that

> First, . . . all ROEs approved pursuant to section 219 will be within the range of reasonableness, as determined consistent with our precedents. Second, any incentive ROEs granted under section 219 should have minimal effect, if any, on the overall range of reasonableness derived from the appropriate proxy group. The DCF methodology uses proxy groups of entire companies, not individual transmission projects. In other words, the "cash flows" being measured in the DCF method are the cash flows of entire companies. These cash flows should not be significantly affected by an incentive return for any particular transmission project for one company within the proxy group. Moreover, to the extent there is any small effect on the overall range of reasonableness, it will appropriately reflect the substantial risks associated with constructing new transmission[.][148]

75. Further, even assuming *arguendo* that this circularity problem exists, it exists for any proxy group company that receives incentive adders and Petitioners have presented no methodology for determining whether or how much a company's incentive adders

---

[147] *See Northwest Pipeline*, 87 FERC ¶ 61,266 at 62,058-59.

[148] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 62 (cross-referenced at 117 FERC ¶ 61,345 at P 62).

might impact investors' expectations for a particular company, particularly where the proxy company at issue is involved in diverse business activities, as is UIL Holdings. Thus, absent more evidence, we are not persuaded that this potential "circularity problem" warrants an adjustment to the NETOs' base ROE. Further, even if Petitioners had shown this alleged circularity to be a legitimate problem warranting an adjustment to the base ROE, Petitioners have not shown that placing the base ROE at their proposed true 75th percentile of the proxy group results would be an appropriate solution.

76. We also reject Petitioners' argument that the Commission should have compared UIL Holdings's IBES growth rate against the Reuters data Trial Staff provided and the "br+sv"[149] data in the record. We relied only on IBES data for the DCF analysis in this proceeding, because that is the only short-term growth data available in the record for all the proxy companies. As the Commission explained in Opinion No. 531, "[u]sing different sources of growth rate data for different companies in a proxy group could produce skewed results, because those sources may take different approaches to calculating growth rates."[150] A comparison between UIL Holdings's IBES data and other non-IBES data in the record would be susceptible to this same skewing effect, and therefore would not provide a reliable comparison. Further, as the Commission explained in Opinion No. 531, while "the purpose of the 'br+sv' growth estimate is to act as a check on the reasonableness of the IBES forecasts," in practice the two sources often produce "widely divergent growth rates that do not engender much confidence in the reliability of the estimates."[151] We are, therefore, not persuaded that it is necessary to compare the IBES growth rate data to the "br+sv" data. In addition, we disagree with Petitioners that declining to mix growth rate sources is inconsistent with Opinion No. 531's allowance of credit ratings from both Moody's and S&P. The purpose of using data from both Moody's and S&P is to identify a group of comparable risk companies. In contrast, the purpose of not using multiple sources of growth rate data is to ensure that the cost of equity for each company in the proxy group is estimated using the same protocols.

77. We also reject Petitioners' argument that the Commission should have used the "br+sv" growth rate as the short-term growth rate in the two-step DCF methodology.

---

[149] The term "br+sv" represents the sustainable growth formula, in the one-step DCF methodology that the Commission used for public utilities prior to Opinion No. 531, where "b" is the percentage of earnings expected to be retained (after the payment of dividends), "r" is the expected rate of return on book equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate.

[150] Opinion No. 531, 147 FERC ¶ 61,234 at P 90.

[151] *Id.* P 37.

While the "br+sv" growth formula relies on short-term Value Line projections of five years or less for the various inputs to the formula, it seeks to estimate a company's "sustainable growth rate." For that reason, although the Commission has stated that the formula "only produces a projection of short-term growth, similar to the IBES projections,"[152] the Commission finds the formula unreasonable for use as the short-term growth projection in the two-step DCF methodology. By seeking to estimate a "sustainable growth rate," the "br+sv" growth formula also contains some elements of a long-term growth projection, in addition to a short-term growth projection, and thus is inappropriate for use as a purely short-term growth projection in a two-step DCF methodology. The Commission adopted the two-step DCF methodology because, among other reasons, its incorporation of a long-term growth projection in the cost of equity calculation would have the effect of ascribing sustainable long-term growth to all members of a proxy group.[153] Thus, the Commission's adoption of the two-step DCF methodology accomplishes what the use of the "br+sv" formula was intended to accomplish.[154]

78. We reject Petitioners' arguments that the Commission erred in its application of the low-end and high-end outlier tests. We reiterate that it is appropriate—and consistent with Commission precedent—to eliminate PSEG as a low-end outlier in this case because PSEG's DCF result is a mere 101 basis points above the applicable bond yield and there is a 141 basis point break between PSEG's DCF result and the next lowest result. Further, we reject as inconsistent with Commission precedent Petitioners' argument that the Commission should have adopted the NETOs' proposed adjustment to the low-end outlier test instead of placing the base ROE above the midpoint of zone of reasonableness. Petitioners have identified no precedent in which the Commission has adopted such an adjustment to the low-end outlier test, and we are not persuaded to do so in this case.

---

[152] *Id.* P 34.

[153] *Id.* PP 38, 40.

[154] We also note that the Commission's rationale for adopting the two-step DCF methodology in Opinion No. 531 was, in part, to use a methodology that is more consistent with the methodology the Commission has applied in natural gas and oil pipeline cases. *See id.* P 36. However, using "br+sv" in place of IBES growth rates, as Complainants request, would produce a DCF methodology that is less closely aligned with the methodology the Commission uses in natural gas and oil pipeline cases, where the Commission has rejected the use of the "br+sv" formula. *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, 123 FERC ¶ 61,048 at P 100.

79. Petitioners next argue that, if the Commission eliminates PSEG as a low-end outlier, it must also eliminate UIL Holdings as a high-end outlier because UIL Holdings's DCF result is 112 basis points above the next highest DCF result, and the Commission must apply the same "natural break" analysis in both the low-end and high-end outlier tests. We disagree. The low-end outlier test and the high-end outlier test serve very different purposes: the low-end outlier test is intended to screen out companies whose ROE estimates are low enough that an investor would consider the stock to yield essentially the same return as debt,[155] whereas the high-end outlier test is intended to screen out companies whose growth rates are unsustainably high and therefore fail a threshold test of economic logic.[156] As the Commission explained in Opinion No. 531, the high-end outlier issue in this proceeding is moot because the two-step DCF methodology assumes that the long-term growth rate of all proxy companies is equal to GDP, and is therefore sustainable.

c. State Commission-Authorized ROEs

i. Opinion No. 531

80. The Commission in Opinion No. 531 found that the record evidence of state commission-approved ROEs supported the Commission's determination that a base ROE at the midpoint of the zone of reasonableness would not satisfy *Hope* and *Bluefield*. The Commission explained that, while it has "repeatedly held that it does not establish utilities' ROE based on state commission ROEs for state-regulated electric distribution assets,"[157] this proceeding presents "circumstances under which the midpoint of the zone of reasonableness established in this proceeding has fallen below state commission-approved ROEs, even though transmission entails unique risks that state-regulated electric distribution does not."[158] More specifically, the Commission explained that "while the midpoint in this case is 9.39 percent, the record indicates that, over the 24-month period from October 1, 2010 through September 30, 2012, approximately 85 percent to 91 percent of state commission authorized ROEs were between 9.8 percent and 10.74 percent."[159] Accordingly, the Commission found that "[a]lthough we are not using the state commission-approved ROEs to establish the NETOs' ROE in this

[155] *See S. Cal. Edison Co.*, 92 FERC ¶ 61,070 at 61,266.

[156] *See, e.g.*, *ISO New England, Inc.*, 109 FERC ¶ 61,147 at P 205.

[157] Opinion No. 531, 147 FERC ¶ 61,234 at P 148.

[158] *Id.*

[159] *Id.*

proceeding, the discrepancy between state ROEs and the 9.39 percent midpoint serves as an indicator that an upward adjustment to the midpoint here is warranted to satisfy *Hope* and *Bluefield*."[160]

ii. Requests for Rehearing

81. Petitioners and EMCOS argue that the Commission erred in relying on state commission-authorized ROEs in Opinion No. 531, because comparisons to state-authorized ROEs are not relevant to this proceeding and do not support raising the NETOs' base ROE from the 9.39 percent midpoint to the 10.57 percent upper quartile figure.[161] Petitioners argue that Opinion No. 531 erroneously relies on the spin that the NETOs placed on Ex. NET-403's data, repeating their argument that "approximately 85 percent to 91 percent of state commission authorized ROEs were between 9.8 percent and 10.74 percent."[162] EMCOS argue that the fact that some state commission-approved ROEs are higher than the midpoint in this proceeding is insufficient evidence to support Opinion No. 531's decision to ignore the Commission's strong preference for the use of the midpoint.[163] Petitioners contend that reference points presented in the exhibit show that 89 percent of the past-period state commission ROE outcomes collected by the NETOs fall below 10.57 percent.[164] Petitioners further contend that the central tendency values of the state commission-authorized ROEs presented by the NETOs are a mode of 10 percent, median of 10.13 percent, a mean of 10.14 percent, and a midpoint of 10.25 percent. Petitioners argue that Opinion No. 531 does not explain how these data justify a 10.57 percent base ROE.[165]

82. Petitioners and EMCOS contend that the state commission-authorized ROEs upon which the Commission relied were tainted by substantial lag, and that relying on them is therefore inconsistent with Opinion No. 531's emphasis on using the most recent

---

[160] *Id.*

[161] Petitioners Request for Rehearing at 23; EMCOS Request for Rehearing at 25-26.

[162] Petitioners Request for Rehearing at 23.

[163] EMCOS Request for Rehearing at 11, 25-26 (citing *Fla. Gas Transmission Co. v. FERC*, 604 F.3d 636, 639 (D.C. Cir. 2010)).

[164] Petitioners Request for Rehearing at 23.

[165] *Id.* at 25.

information available in the record.[166] Petitioners argue that the record shows that more recent state-authorized base ROEs have averaged below 10 percent. For example, Petitioners state that the Regulatory Research Associates data for the first quarter of 2013 show that the average authorized state electric ROE "approximated 9.75 [percent], 25 [basis points] below the analogous adjusted average ROE for calendar-2012 (which approximated 10 percent)."[167] Petitioners state that Exhibit SC-423 shows that, on March 15, 2013, the New York State Public Service Commission approved an ROE of 9.3 percent for Niagara Mohawk Power Corporation, finding the rate to be "consistent with investor expectations while being slightly below other recently authorized rate plans."[168] In addition, Petitioners state that Exhibit SC-505 shows that, at around the same time, Northeast Utilities' retail ROE was set at 9.38 percent.[169]

83. Petitioners contend that the Commission should have made its own independent finding of the current cost of equity, based on financial market data, rather than being constrained by stale decisions reached elsewhere. Petitioners note that the Commission has previously rejected efforts to use state commission-authorized ROEs as a benchmark for setting regional transmission ROEs.[170] Petitioners argue that if state commission-authorized ROEs are irrelevant when they are lower than the result of the Commission's DCF analysis, then they are also irrelevant when they are higher than the result of the Commission's DCF study. Petitioners argue that the Commission's failure to recognize this symmetry in Opinion No. 531 or to offer any justification for ignoring it renders the decision arbitrary and capricious.[171] Similarly, EMCOS contend that Opinion No. 531 is inconsistent with *Missouri Public Service Commission v. FERC,* 337 F.3d 1066, 1077 (D.C. Cir. 2003) (*Missouri*), which explained that "[w]hen FERC relies upon a state agency's prior approval to support the conclusion that rates are in the public interest, the Commission must at least say something about the prior regulator's rationale for approving those rates."

---

[166] *Id.* at 25-26 (citing Opinion No. 531, 147 FERC ¶ 61,234 at PP 55, 88); EMCOS Request for Rehearing at 11, 26 (citing *NorAm Gas Transmission Co. v. FERC*, 148 F.3d 1158, 1165 (1998)).

[167] Petitioners Request for Rehearing at 26.

[168] *Id.* at 28 (citing Ex. SC-423 at 18).

[169] *Id.*

[170] *Id.* at 29.

[171] *Id.* at 29-30.

iii. Commission Determination

84. We disagree with Petitioners' and EMCOS's arguments that the record evidence concerning state commission-authorized ROEs does not support placing the NETOs' base ROE above the midpoint of the zone of reasonableness. The Commission did not use the evidence of state commission-authorized ROEs to determine the level at which the NETOs' base ROE should be set. As explained below, the Commission merely relied on the state commission-authorized ROEs—in conjunction with evidence that interstate transmission is riskier than state-level distribution—as evidence that the 9.39 percent midpoint of the DCF-produced zone of reasonableness was insufficient to satisfy the requirements of *Hope* and *Bluefield* and, therefore, that an adjustment above 9.39 percent was warranted.[172]

85. Contrary to Petitioners' and EMCOS's arguments, applying other measures of central tendency to the NETOs' data on state commission-authorized ROEs does not undermine the Commission's conclusion that an upward adjustment was warranted. Petitioners point to various measures of central tendency for the state commission-authorized ROEs: mode of 10 percent, median of 10.13 percent, a mean of 10.14 percent, and a midpoint of 10.25 percent. But all of these figures are above the 9.39 percent midpoint of the zone of reasonableness; in light of the record evidence showing that interstate transmission is riskier than state-level distribution,[173] all of these figures support adjusting the NETOs' base ROE above that level. Further, while Petitioners focus on the fact that 89 percent of the state commission-authorized ROEs in the NETOs' study are below 10.57 percent, that fact is irrelevant to how the midpoint of the DCF-produced zone of reasonableness compares to the state commission-authorized ROEs. The more relevant fact is that almost 93 percent of the state commission-authorized ROEs are above the 9.39 percent midpoint produced by the Commission's two-step DCF methodology in this case.[174]

86. We reject Petitioners' and EMCOS's arguments that the Commission's reliance on the state ROE figures despite their time-lag is inconsistent with the Commission's preference for the most recent data in the record. The evidence of state commission-

---

[172] *See* Opinion No. 531, 147 FERC ¶ 61,234 at PP 148-149.

[173] *See id.* P 149. We note that Petitioners have not refuted the record evidence that interstate transmission is riskier than state-level distribution. Petitioners' request for rehearing discusses the Commission's finding on the relative risks of transmission and distribution only in the context of whether the NETOs are more or less risky than the companies in the DCF proxy group. *See* Petitioners Request for Rehearing at 19-22.

[174] *See* Ex. NET-403.

authorized ROEs that the Commission relied upon is, in fact, the most recent complete study in the record. While the record does contain some more recent evidence of state commission-authorized ROEs, that evidence does not represent a data set comparable to the NETOs' 24-month study,[175] but is rather data for only one quarter in 2013 from Regulatory Research Associates concerning the recent trend in average authorized ROEs. According to Petitioners, the report from Regulatory Research Associates indicates that the average state commission-authorized ROE in the first quarter of 2013 "approximated 9.75 [percent], 25 [basis points] below the analogous adjusted average ROE for calendar-2012 (which approximated 10 percent)."[176] This evidence does not undermine, but supports, the Commission's conclusion that the 9.39 percent midpoint, determined by using the DCF methodology, is below most of the state ROEs.

87. We also reject Petitioners' argument that, in using state commission-authorized ROEs to corroborate the outcome of the DCF analysis, the Commission failed to make its own finding on the cost of equity. To the contrary, the Commission conducted its own DCF analysis and did make its own finding, based on the financial market data in the record. That the Commission looked to the state commission-authorized ROEs and alternative methodologies to corroborate the accuracy of its finding, does not undermine the Commission's finding on the cost of equity. Rather, the Commission's analysis of not only the DCF results but also additional record evidence demonstrates that the Commission fully reviewed the record to ensure a just and reasonable ROE sufficient to meet the capital attraction standards required by *Hope* and *Bluefield.*

88. We disagree that the Commission's use of state commission-authorized ROEs in Opinion No. 531 is inconsistent with Commission precedent. As the Commission explained in Opinion No. 531, while the Commission has rejected the use of state ROEs

---

[175] The NETOs' study of state commission-allowed ROEs covered the time period from October 1, 2010 through September 30, 2012. *See* Ex. NET-400; Ex. NET-403.

[176] Petitioners Request for Rehearing at 26 (citing Ex. SC-524). We note that the Regulatory Research Associates' report states that the average state commission-allowed ROE for the first quarter of 2013 is 10.24 percent. The 9.75 percent figure to which Petitioners refer was calculated by excluding from the ROE decisions issued in that quarter those from one particular state commission and, as noted, would be 10.24 percent without that exclusion. Further, we note that the record evidence also shows that the average state commission-allowed ROE for the fourth quarter of 2012, i.e., the quarter immediately following the time period of the NETOs' state ROE study, was 10.10 percent. Thus, the data concerning state commission allowed-ROEs for the fourth quarter of 2012 (10.10 percent) and the first quarter of 2013 (10.24 percent) are consistent with the data in the NETOs' study of state commission-allowed ROEs, and do not indicate a downturn in state ROEs as Petitioners allege.

in the past, it has done so on the grounds that the state ROEs alone provide an insufficient basis for determining Commission-jurisdictional rates. Those cases are distinguishable from the instant proceeding, where the Commission instead compared the evidence provided by a significant number of state commission-authorized ROEs to the midpoint produced by the application of the Commission's traditional methodology and concluded that their levels, relative to each other, were illogical in light of the record evidence concerning the comparative risks of state-level electric distribution and interstate electric transmission. We also reject Petitioners' argument that, if state commission-approved ROEs are irrelevant when they are below Commission ROEs, then they are also irrelevant when they are above Commission ROEs. The Commission has not found state commission-approved ROEs to be irrelevant when they are lower than Commission-approved ROEs. As the Commission explained in Opinion No. 531, the relevance of the state commission-approved ROEs was determined in conjunction with the record evidence on the elevated risks of interstate transmission, compared to state-regulated distribution.

89. Lastly, we disagree with EMCOS's assertion that the Commission ignored *Missouri*, 337 F.3d 1066. *Missouri* is inapposite to the facts of this case as it involved the Commission's *adoption* of a specific rate, for a gas pipeline's sales under the Commission's jurisdiction, that had been "approved by [a state commission] under the regulatory regime that governed the pipeline prior to FERC's assertion of jurisdiction."[177] By comparison, in Opinion No. 531, the Commission did not adopt any rate approved by a state commission.

d. Risk Premium Analysis

i. Opinion No. 531

90. In Opinion No. 531, the Commission explained that the risk premium methodology is "based on the simple idea that since investors in stocks take greater risk than investors in bonds, the former expect to earn a return on a stock investment that reflects a 'premium' over and above the return they expect to earn on a bond investment."[178] The Commission further explained that "investors' required risk premiums expand with low interest rates and shrink at higher interest rates," and found that this link "provides a helpful indicator of how investors' required returns on equity

---

[177] *Missouri*, 337 F.3d at 1076.

[178] Opinion No. 531, 147 FERC ¶ 61,234 at P 147 (quoting Roger A. Morin, New Regulatory Finance 108 (Public Utilities Reports, Inc. 2006)) (internal quotations omitted).

have been impacted by the interest rate environment."[179] The Commission explained that it has in the past rejected the use of risk premium analyses to estimate investor-required returns on equity, but "those cases are distinguishable from the instant proceeding because they involved proposals to establish a constant risk premium based on the average difference between state commission ROEs and bond rates over multi-year periods."[180]

91. The Commission found the NETOs' risk premium analysis "informative,"[181] as it indicated that the NETOs' cost of equity "is between 10.7 percent and 10.8 percent, which is higher than the 9.39 percent midpoint produced by our DCF analysis."[182] The Commission explained that, in relying on the NETOs' risk premium analysis, "we do not depart from our use of the DCF methodology; rather, we use the record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness established in the record by the DCF methodology."[183]

ii. <u>Requests for Rehearing</u>

92. EMCOS argue that Opinion No. 531 erred by adopting the NETOs' risk premium analysis despite the fact that the Commission has repeatedly rejected the use of risk premium analysis for determining a just and reasonable ROE for a public utility.[184] EMCOS assert that the Commission in Opinion No. 531 attempted to distinguish those precedents from this proceeding on the basis that the risk premium analyses in those cases relied on "the average state commission ROEs and bond rates over multi-year periods."[185] However, EMCOS contend that the Commission's rationale is flawed because the Commission's rejection of risk premium analyses in the past was not due to the involvement of state commission ROEs, but rather was due to concerns regarding the

---

[179] *Id.*

[180] *Id.* n.290.

[181] *Id.* P 146.

[182] *Id.* P 147.

[183] *Id.* P 146.

[184] EMCOS Request for Rehearing at 20-21 (citing *Consumers Energy Co.*, 64 FERC ¶ 63,029 (1993), *aff'd*, 85 FERC ¶ 61,100 at 61,361 (1998); *New England Power Co.*, 31 FERC ¶ 61,378, at 61,841 (1985)).

[185] *Id.* at 21 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 147 n.290).

reliability of the methodology to produce reliable results in fluctuating market conditions.[186] Additionally, EMCOS argue that Opinion No. 531 fails to respond to criticism that parties presented about the NETOs' risk premium analysis. EMCOS argue that Opinion No. 531's failure to respond to—or even acknowledge—the substantive arguments against the NETOs' specific risk premium analysis renders the decision arbitrary and capricious.[187]

93. Petitioners argue that the NETOs' version of a risk premium analysis contains multiple flaws. Petitioners argue that the NETOs' risk premium analysis detaches the ROEs from the regulatory contexts in which they were approved, and this disconnect should have rendered the NETOs' risk premium study irrelevant as a matter of law.[188] In addition, Petitioners assert that, even if it were acceptable to detach the allowed ROEs from their regulatory contexts, the NETOs' risk premium study's attempt to discern regulatory outcomes and assign dates to those outcomes contains numerous errors. Specifically, Petitioners contend that the risk premium study was performed by a person who did not appear at trial, lacked professional expertise in reading Commission decisions, and used examples supplied by the NETOs' counsel rather than a random or representative sample. Petitioners also argue that the NETOs' risk premium study is flawed because it assumes that the outcomes of Commission proceedings represent equity costs on the day the Commission issued its order approving the ROE, thereby ignoring both regulatory lag and the reality that many Commission decisions that identify an ROE do not involve finding a new, currently cost-based ROE.[189]

94. Additionally, Petitioners argue that the NETOs' risk premium study is flawed because the study makes no attempt to screen its inputs for comparable risk.[190] As an

---

[186] *Id.* (citing *Consumers Energy Co.*, 64 FERC ¶ 63,029, *aff'd*, 85 FERC ¶ 61,100 at 61,361; *New England Power Co.*, 31 FERC ¶ 61,378 at 61,841).

[187] *Id.* at 22 (citing *Ill. Pub. Telecomm. Ass'n v. FCC*, 117 F.3d at 564).

[188] *Id.* at 33-34 (citing *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176, at P 127 (2008), *reh'g denied*, 139 FERC ¶ 61,144 (2012)).

[189] Similarly, EMCOS note that Trial Staff and the Complainants argued that the NETOs' risk premium analysis is based on Commission-allowed returns, which are not the same as the market indicated ROEs that this methodology claims to address. Moreover, EMCOS explain that the NETOs' analysis includes ROEs that are the result of settlements, which further skew the results. In addition, EMCOS explain that the NETOs' analysis is rife with errors regarding the applicable dates of the Commission approved ROEs upon which they rely.

[190] Petitioners Request for Rehearing at 35.

example illustrating this flaw, Petitioners state that the NETOs' risk premium study treated as representative of June 2012 risk premiums—without making any finding as to the current equity cost—a Commission order that merely extended to a new MISO participant the 12.38 percent ROE that was established for the MISO region more than a decade earlier.[191] Petitioners further state that the Commission, in Opinion No. 489, rejected the NETOs' reliance on MISO's 12.38 percent ROE as a benchmark for New England.[192] Petitioners also argue that the NETOs' risk premium study treats orders and data from 2008-2009 as comparable to the NETOs' ROE, which was established in 2006 based on data from 2004. The Petitioners further assert that the NETOs' study failed to include orders after June 2012, and that these omissions skewed the NETOs' results by missing the trend towards lower ROEs.

95. Petitioners argue that, although the NETOs' failed to present an informative risk premium study, they did provide a basis to construct a more useful one that accords with Opinion No. 531's discussion of the theory underlying the risk premium methodology. Specifically, Petitioners note Opinion No. 531's explanation that "investors' required risk premiums expand with low interest rates and shrink at high interest rates,"[193] and assert that the NETOs' risk premium study used an incorrect ratio in determining the rate at which risk premiums change in response to changes in interest rates. Petitioners argue that the NETOs' risk premium study relied on an inferred rate at which risk premiums expand when interest rates drop is about 93:100—i.e., a 100 basis points decline in interest rates is deemed to be offset by a risk premium increase of about 93 basis points—which leaves a net decline in the cost of equity of only 7 basis points for every 100 basis point change interest rates. However, Petitioners contend that the NETOs' witness disavowed that ratio at trial, by clarifying that "generally, one half of the move in equity returns [is] related to the move in bond returns," so "if bond returns go up 100 basis points, your best guess of equity costs is 50 or 60 basis points."[194] Therefore, Petitioners state that it is more appropriate to use 45:100[195] as the rate at which risk premiums expand when interest rates drop—i.e., a 100 basis points decline in interest rates is deemed to be offset by a risk premium increase of about 45 basis points—which leaves a net decline in the cost of equity of 55 basis points for every 100 basis point change in

---

[191] *Id.*

[192] *Id.* at 36.

[193] *Id.* at 37 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 147).

[194] *Id.* at 38.

[195] Petitioners calculate this ratio by taking the average of the 50-60 basis point range indicated by the NETOs' witness at trial.

interest rates. Petitioners argue that substituting that relationship in Ex. NET-704 for the implausible 93:100 ratio, indicates an ROE of 9.67 percent to 9.91 percent.[196]

96. Petitioners contend that Opinion No. 531's reliance on a stale and poorly designed study of past Commission orders was inconsistent with its finding that ROEs should reflect the most recent information available at the time of trial.

iii. Commission Determination

97. We deny rehearing on the issue of whether the NETOs' risk premium analysis is flawed. As the Commission explained in Opinion No. 531, the theory behind the risk premium methodology is that "since investors in stocks take greater risk than investors in bonds, the former expect to earn a return on a stock investment that reflects a 'premium' over and above the return they expect to earn on a bond investment."[197] There are multiple approaches that have been advanced to determine this equity risk premium for a utility.[198] For example, a risk premium can be developed directly, by conducting a risk premium analysis for the company at issue, or indirectly by conducting a risk premium analysis for the market as a whole and then adjusting that result to reflect the risk of the company at issue.[199] Another approach that investors might choose to look to in the utility context is to "examin[e] the risk premiums implied in the returns on equity allowed by regulatory commissions for utilities over some past period relative to the contemporaneous level of the long-term Treasury bond yield."[200] In the instant case, the NETOs followed the latter approach, developing their risk premium study by analyzing the ROEs allowed by this Commission since April 2006,[201] relative to the

---

[196] Petitioners Request for Rehearing at 38.

[197] Roger A. Morin, New Regulatory Finance 108 (Public Utilities Reports, Inc. 2006).

[198] *See generally id.* at 107-130.

[199] *Id.* at 110.

[200] *Id.* at 123.

[201] *See* Ex. NET-704 at 3-4. We note that, although Petitioners assert that the NETOs failed to include any Commission orders issued after June 2012, Petitioners have not cited any final Commission orders establishing a utility's ROE between June 2012 and the date the Presiding Judge set as the deadline for the parties to update their exhibits prior to the hearing. While Petitioners correctly note that the Commission issued such an ROE order on May 6, 2013, that decision was issued after the final updating of exhibits.

contemporaneous level of the long-term Treasury bond yield,[202] to determine the risk premium implied by those regulatory decisions.[203]

98. Petitioners allege that the NETOs' risk premium analysis is flawed because it assigned arbitrary dates to the regulatory decisions on which it was based, ignored the fact that some of the decisions involved rates agreed to by settlement, ignored regulatory lag, and ignored the reality that some of the decisions did not involve the calculation of a current cost of equity. Given the varying duration of regulatory proceedings, it is difficult, if not impossible, to ensure precise contemporaneity between long-term Treasury bond yields and the cost of equity allowed by a regulator. Assigning approximate dates to the cost of equity determinations made in those regulatory proceedings, as the NETOs have done, is often unavoidable, and this fact alone does not undermine the relevance of risk premium analyses.[204] Similarly, whether the regulatory decision involved a settlement agreement or the application of a cost of equity that was calculated in the past, e.g., the 12.38 percent ROE established for the MISO region, does not affect the reliability of a risk premium analysis.[205] Risk premiums allowed by

---

[202] NETOs also analyzed the ROEs allowed by regulatory decisions relative to long-term utility bond yields.

[203] *See* Ex. NET-704 at 1-2.

[204] We disagree with Petitioners that the Commission's reliance on the NETOs' risk premium analysis, despite the regulatory lag reflected therein, is inconsistent with Opinion No. 531's finding that "ROEs should reflect the most recent information available at the time of trial." Petitioners Request for Rehearing at 37. The NETOs' risk premium study upon which the Commission relied is indeed the most recent such study in the record.

[205] Further, contrary to Petitioners' assertion, the fact that the Commission, in Opinion No. 489, declined to use the 12.38 percent ROE from the MISO region as a benchmark in establishing the NETOs base ROE has no bearing on this proceeding. Using the ROE from the MISO region as a benchmark in establishing the just and reasonable ROE for the NETOs' is much different than using the ROE from the MISO region as one data point, among many, in a risk premium analysis that is then used to corroborate the results of the Commission's analysis. Additionally, assuming *arguendo* that (1) the 12.38 percent ROE for the MISO region was "stale" in June 2012, *see* Petitioners' Request for Rehearing at 35, (2) the 11.14 percent base ROE for the NETOs' was "stale" in August, November, and December of 2008, *see id.* at 36, and (3) it is therefore appropriate to exclude those data points from the NETOs' risk premium study, Petitioners have not shown that excluding those data points would materially affect the results of the NETOs' risk premium study or undermine its usefulness in

(continued…)

regulators "are presumably based on the results of market-based methodologies presented to regulators in rate hearings and on the actions of objective unbiased investors in a competitive marketplace."[206] This is no less true in the case of settlement agreements, as settling parties rely upon the same market-based methodologies in determining the rates they are willing to accept. In short, while the approach the NETOs used in their risk premium analysis, like any methodology for estimating the cost of equity, is not without inherent weaknesses, it is nonetheless an approach that investors routinely rely upon.[207] We similarly find the NETOs' risk premium analysis sufficiently reliable—not to set the ROE itself—but rather to corroborate our decision to place the NETOs' base ROE above the midpoint of the zone of reasonableness produced by the DCF analysis.

99. We also reject Petitioners' argument that the NETOs' risk premium study does not support placing the NETOs' base ROE above the midpoint of the zone of reasonableness because the NETOs' assumption regarding the inferred rate at which risk premiums expand when interest rates drop—i.e., the assumption that risk premiums expand by 93 basis points for every 100 basis point drop in interest rates—is unsupported. Petitioners assert that, if the NETOs' study is adjusted to reflect a more appropriate ratio than 93:100, the NETOs' risk premium study produces a result between 9.67 and 9.91 percent. While the rate at which risk premiums change as interest rates change is indeed important in a risk premium analysis, we find the alleged flaw to be immaterial in this context in

---

corroborating the results of the Commission's DCF analysis. The NETOs' risk premium analysis compared the ROEs established in 66 cases from April 2006 through June 2012 to the contemporaneous 10-year U.S. Treasury bond yields to determine 66 risk premiums, which averaged 7.33 percent. Excluding the alleged stale ROEs would eliminate five of the 66 risk premiums from the NETO's analysis. The remaining 61 risk premiums average 7.28 percent, only marginally less than the average of the 66 risk premiums used in the NETOs' analysis. This indicates that exclusion of the allegedly stale ROEs would not materially reduce the 10.7 percent to 10.8 percent cost of equity produced by the NETOs' risk premium analysis.

[206] Roger A. Morin, New Regulatory Finance 125 (Public Utilities Reports, Inc. 2006).

[207] *Id.* at 123-125. We reject Petitioners' assertion that the NETOs' risk premium study was conducted by an unqualified analyst who did not appear at trial. The analyst to whom Petitioners refer did not conduct the NETOs' risk premium analysis, but rather assisted the NETOs' expert witness in conducting the analysis. *See* Tr. 647:9-648:10. Further, the analyst at issue is a chartered financial analyst, with a Masters Degree in Business Administration, who has assisted the NETOs' expert witness in preparing testimony in over 100 Commission proceedings. *See id.* at 648:14-22.

this case. As an initial matter, the alternative inferred rate—a ratio of 45:100—that Complainants put forth based on the NETOs' witness's testimony at hearing was based on state commission-allowed ROEs, not interstate transmission ROEs allowed by this Commission.[208] In light of the record evidence on the risk differential between state-regulated distribution and Commission-regulated interstate transmission, we are not persuaded that it is appropriate to apply to the NETOs, for the time period at issue in this proceeding, the inferred rate relationship between risk premiums and interest rates that was observed in state commission-allowed ROEs over a time period dating back a quarter century, to 1987. Further, the NETOs' determined the inferred rate relationship between risk premiums and interest rates in their risk premium study by conducting empirical observations and regression analysis of bond yields and Commission-allowed ROEs.[209] In sum, we are not persuaded that the NETOs' empirical results are invalid simply because they differ from the inferred rate relationship reflected in historical state commission-approved ROEs, particularly where anomalous capital market conditions exist that may impact the inferred relationship between risk premiums and interest rates.

100. EMCOS argue that the Commission erred in relying on the NETOs' risk premium analysis because doing so is inconsistent with precedent in which the Commission has rejected the use of risk premium analyses.[210] EMCOS assert that the Commission in Opinion No. 531 attempted to distinguish those precedents on the grounds that the risk premium analyses therein involved state commission-allowed ROEs. EMCOS contend that the Commission's interpretation of those precedents is incorrect, because the Commission in fact rejected the use of risk premium analyses in those past cases due to concerns that risk premium analyses are unreliable under fluctuating market conditions.

101. In Opinion No. 531, the Commission explained that the Commission's rejection of the risk premium analysis in a number of past cases, including *New England Power Co.*, is distinguishable from the instant case because those cases involved "*proposals to establish a constant risk premium* based on the average difference between state commission ROEs and bond rates *over multi-year periods*."[211] EMCOS mischaracterize the Commission's interpretation of *New England Power Co.* and other similar precedents

---

[208] *See* Tr. 606:5-7 ("this is based on state returns, and state returns have marched to a slightly different drummer than FERC returns over the years.").

[209] *See generally* Ex. NET-704.

[210] EMCOS Request for Rehearing at 20-21 (citing *Consumers Energy Co.*, 64 FERC ¶ 63,029, *aff'd*, 85 FERC ¶ 61,100 at 61,361; *New England Power Co.*, 31 FERC ¶ 61,378 at 61,841).

[211] Opinion No. 531, 147 FERC ¶ 61,234 at n.290 (emphasis added).

by focusing on Opinion No. 531's reference to the fact that the risk premium analyses in the past cases relied upon state commission ROEs. As the italicized language in the above quote makes clear, however, the Commission's rationale for rejecting the proposal in *New England Power Co.* was not merely reliance on state commission-set ROEs, but was, as EMCOS correctly acknowledge, based on the Commission's finding that "[t]here is no direct relationship between historical risk premiums and a current cost of equity under constantly changing financial conditions."[212] In *New England Power Co.*, the utility proposed to calculate a risk premium based on the difference between the most recent 20-year average yield for certain money market indicators and the most recent 20-year average annual yield for Moody's Electric Utility common stocks plus the 10-year growth in dividends for those stocks. Thus, the utility assumed a constant risk premium for a 20-year period. In the instant case, the NETOs' risk premium analysis does not assume a constant risk premium over any length of time. Rather, the NETOs calculated a varying risk premium based on variations in the difference between allowed ROEs and bond yields during the time period from April 2006 through June 2012. Those cases in which the Commission rejected risk premium analyses in the past are thus distinguishable from the instant case, because unlike the proposals in those cases the NETOs have not proposed their risk premium analysis to establish a constant risk premium.[213]

e. <u>CAPM Analysis</u>

i. <u>Opinion No. 531</u>

102. In Opinion No. 531, the Commission explained that "[s]imilar to the risk premium analysis, the NETOs' CAPM uses interest rates as the input for the risk-free rate, which makes it useful in determining how the interest rate environment has impacted investors' required returns on equity."[214] The Commission also explained that "CAPM is utilized by investors as a measure of the cost of equity relative to its risk."[215] The Commission

---

[212] *New England Power Co.*, 31 FERC at 61,841.

[213] Moreover, unlike other cases, the Commission here is *not* setting investor-required ROEs based on this risk premium, but is instead looking to it merely as "a helpful indicator" of the impact of the "interest rate environment" on "investors' required returns on equity." And from this analysis (and others discussed elsewhere in Opinion No. 531 and here) the Commission concludes only that the ROE should indeed be set above the midpoint. *See* Opinion No. 531, 147 FERC ¶ 61,234 at P 147 & n.290.

[214] Opinion No. 531, 147 FERC ¶ 61,234 at P 147.

[215] *Id.*

explained that it has in the past rejected the use of CAPM analyses, but "those cases are distinguishable from the instant proceeding because they involved CAPM analyses that were based on historic market risk premiums," whereas the NETOs' CAPM analysis "is based on forward-looking investor expectations for the market risk premium."[216]

103. The Commission found the NETOs' CAPM analysis "informative,"[217] as it produced a midpoint of 10.4 percent and a median of 10.9 percent, both of which are above the 9.39 percent midpoint produced by the Commission's DCF analysis.[218] The Commission explained that, in relying on the NETOs' CAPM analysis, "we do not depart from our use of the DCF methodology; rather, we use the record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness established in the record by the DCF methodology."[219]

ii. <u>Requests for Rehearing</u>

104. Petitioners assert that the NETOs' CAPM study is flawed because its assumption that the market as a whole (i.e., most of the S&P 500 companies) will grow at an annual rate of 10.3 percent is overly optimistic, unsustainable, double the historical norms and projections, and inconsistent with the GDP estimate the Commission relied upon in Opinion No. 531 for other purposes.[220] Petitioners argue that the NETOs calculated the unsustainable 10.3 percent growth rate by screening out almost a quarter of the market and placing excessive weight on the projections of non-utility companies' medium-term earnings per share growth while ignoring the fact that those estimates reflect unsustainable short-term stock repurchase programs and are not long-term projections.

105. Petitioners contend that the NETOs' CAPM study is also flawed because it relies on stock betas, which Petitioners assert are unreliable and do not meaningfully measure the risk differential between the proxy group and the dividend paying portion of the S&P 500 companies.[221] Petitioners state that the Commission in *ITC Holdings* found betas to

---

[216] *Id.* n.292.

[217] *Id.* P 146.

[218] *Id.* P 147.

[219] *Id.* P 146.

[220] Petitioners Request for Rehearing at 39.

[221] *Id.* at 40 (citing *ITC Holdings Corp.*¸121 FERC ¶ 61,229, at P 43 (2007)); EMCOS Request for Rehearing at 23.

be an unreliable predictor of risk and, as a result, found the CAPM methodology to be inappropriate for determining a company's ROE.[222] Petitioners assert that, while the Commission in Opinion No. 531 attempted to distinguish *ITC Holdings* on the basis that it involved historical risk premiums, Opinion No. 531 did not attempt to address *ITC Holdings*'s finding that betas are unreliable. Similarly, EMCOS assert that, because the NETOs' CAPM analysis relied on betas, that analysis failed to incorporate forward-looking expectations, which undermines the Commission's claim that the NETOs' CAPM analysis is based on "forward-looking investor expectations" and is, therefore, distinguishable from CAPM analyses the Commission has rejected in the past.[223] Petitioners assert that their witness and Trial Staff's witness both presented more credible, forward-looking CAPM studies indicating a cost of equity of 7.5 percent and 8.2 percent, respectively, but that the Commission ignored both of these CAPM studies in Opinion No. 531.

106. In addition, Petitioners contend that the NETOs' CAPM study is flawed because it includes a "size adjustment" based on the theory that smaller companies are riskier and should, therefore, have higher growth and higher returns than the average company in the sample set. Petitioners argue that the NETOs' rationale is undermined by the Petitioners' calculation showing that the smaller firms in the NETOs' sample set have lower-than-average growth—an unweighted average of 9.8 percent, compared to the NETOs' weighted average of 10.3 percent.[224] Petitioners also argue that academic studies have shown that it is improper to apply this type of "size adjustment" to utilities.[225] Petitioners state that, without the size adjustment, the median and midpoint of the NETOs' CAPM analysis is 9.7 percent.[226]

107. EMCOS argue that the NETOs' CAPM analysis is flawed because it used a risky 30-year bond interest rate for the risk-free component of the calculation and inappropriately used a DCF result for the risk premium element of the analysis.

---

[222] Petitioners Request for Rehearing at 31 (citing *ITC Holdings*¸121 FERC ¶ 61,229 at P 43; *Orange & Rockland Utils., Inc.,* Opinion No. 314, 44 FERC ¶ 61,253 (*Orange & Rockland*), *order on reh'g*, Opinion No. 314-A, 45 FERC ¶ 61,252 (1988), *reh'g denied*, 46 FERC ¶ 61,036 (1989)).

[223] EMCOS Request for Rehearing at 23 (citing Opinion No. 531, 147 FERC ¶ 61,234 at P 147 n.292).

[224] Petitioners Request for Rehearing at 41 (citing Ex. SC-514).

[225] *Id.* at 42 (citing SC-200 at 35-36).

[226] *Id.*

iii. Commission Determination

108. We deny rehearing on the issue of whether the NETOs' CAPM analysis is flawed. The CAPM methodology has three inputs: the risk-free rate, betas, and the market risk premium.[227] The risk-free rate and betas used in a CAPM study are generally not controversial. The risk-free rate is represented by a proxy, typically the yield on 30-year Treasury bonds.[228] Betas, which measure a stock's risk relative to the market, are published by several commercial sources. The market risk premium, which is where most CAPM studies diverge, can be estimated either using a backward-looking approach, a forward-looking approach, or a survey of academics and investment professionals.[229] A CAPM analysis is backward-looking if its market risk premium component is determined based on historical, realized returns.[230] A CAPM analysis is forward-looking if its market risk premium component is based on a DCF study of a large segment of the market.[231] In a forward-looking CAPM analysis, the market risk premium is calculated by subtracting the risk-free rate from the result produced by the DCF study.[232]

109. In this proceeding, the NETOs submitted a forward-looking CAPM study, using 30-year Treasury bonds for the risk-free rate, betas published by Value Line, and a market risk premium based on a DCF study of all S&P 500 companies that were paying dividends. The NETOs' CAPM approach is a generally accepted methodology routinely relied upon by investors and, therefore, one appropriately used to corroborate our own analysis. As discussed below, we reject the arguments that the NETOs' CAPM analysis contains flaws that undermine its usefulness as corroborative evidence, in determining whether the midpoint of the zone of reasonableness produced by the Commission's DCF analysis provides the NETOs a return that satisfies the requirements of *Hope* and *Bluefield*.

110. As an initial matter, we reject EMCOS's argument that the NETOs' CAPM analysis is flawed because it used a DCF study to determine the market risk premium. As

---

[227] Roger A. Morin, New Regulatory Finance 150 (Public Utilities Reports, Inc. 2006).

[228] *Id.* at 151.

[229] *Id.* at 155-162.

[230] *Id.* at 155-156.

[231] *Id.* at 159-160.

[232] *See id.* at 150, 155.

explained above, using a DCF study is the standard method of calculating the market risk premium in a forward-looking CAPM analysis.[233] We are, therefore, unpersuaded that the use of a DCF study renders the NETOs' CAPM analysis deficient. We also disagree with Petitioners' argument that the NETOs' CAPM analysis relied on an overly optimistic growth rate input in determining the market risk premium. The growth rate in the NETOs' CAPM analysis is based on IBES data, which the Commission has long relied upon as a reliable source of growth rate data.[234]

111. While Petitioners' assert that the growth rate input is inflated because the NETOs calculated it based on only those S&P 500 companies that were paying dividends, we are not persuaded that the exclusion of those companies not paying dividends skewed the growth rate input. As the NETOs' witness correctly explained during the hearing, a DCF analysis can only be conducted for companies that pay dividends.[235] Accordingly, the proxy group in our DCF analysis consists of companies that pay dividends. Basing a CAPM study on only dividend-paying companies is therefore appropriate in this context, where the Commission is looking to the CAPM study to corroborate the results of a DCF analysis, because doing so produces a growth rate input that is more representative of the DCF proxy group than a CAPM study based on non-dividend-paying companies would be. Further, we are not persuaded by Petitioners' argument that non-dividend-paying companies have lower growth rate estimates than dividend-paying companies, because in many situations the opposite is true due to non-dividend-paying companies decision to retain and reinvest more of their earnings, rather than pay dividends.

112. We are also unpersuaded that the growth rate projection in the NETOs' CAPM study was skewed by the NETOs' reliance on analysts' projections of non-utility companies' medium-term earnings growth, or that the study failed to consider that those analysts' estimates reflect unsustainable short-term stock repurchase programs and are not long-term projections. As explained above, the NETOs based their growth rate input on data from IBES, which the Commission has found to be a reliable source of such data. Thus, the time periods used for the growth rate projections in the NETOs' CAPM study are the time periods over which IBES forecasts earnings growth. Petitioners' arguments against the time period on which the NETOs' CAPM analysis is based are, in effect, arguments that IBES data are insufficient in a CAPM study. We disagree. We acknowledge that CAPM analyses may be based on different time periods; however, without more evidence, i.e., a CAPM analysis based on a longer time period, we are not persuaded that the time period on which the NETOs' based their CAPM analysis

---

[233] *See supra* P 108.

[234] *See supra* PP 71-72.

[235] *See* Tr. 740: 3-4.

undermines the relevance of that analysis in corroborating the results of the Commission's DCF analysis.

113. Further, the fact that the Commission's two-step DCF methodology incorporates a long-term growth rate does not necessitate the incorporation of a long-term growth rate in the DCF study the NETOs used to develop the market risk premium for their CAPM analysis. The Commission's rationale for incorporating a long-term growth rate estimate in DCF analyses for public utilities was that it is often unrealistic and unsustainable for high short-term growth rates to continue in perpetuity.[236] Under the CAPM model, the market risk premium is based on the difference between the "required return on the overall market" and the risk-free rate.[237] The required return on the overall market is determined by conducting a DCF study of "a representative market index, such as the Standard & Poor's 500 Index."[238] As noted above, the NETOs developed the market risk premium in their CAPM analysis in exactly this way, by conducting a DCF analysis of the dividend-paying companies in the S&P 500 to determine the required return on the overall market. The rationale for incorporating a long-term growth rate estimate in conducting a two-step DCF analysis of a specific group of utilities does not necessarily apply when conducting a DCF study of the companies in the S&P 500. That is because the S&P 500 is regularly updated to include only companies with high market capitalization. While an individual company cannot be expected to sustain high short-term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization, and the record in this proceeding does not indicate that the growth rate of the S&P 500 stock index is unsustainable.

114. We also reject EMCOS's argument that the NETOs' CAPM analysis was flawed because it relied on a "risky 30-year bond interest" to calculate the risk-free rate. As noted above, 30-year U.S. Treasury bond yields are a generally accepted proxy for the risk-free rate in a CAPM analysis, and are also considered superior to short- and intermediate-term bonds for this purpose.[239] Therefore, absent record evidence to the

---

[236] Opinion No. 531, 147 FERC ¶ 61,234 at P 36 n.63 (citing Roger A. Morin, New Regulatory Finance 308 (Public Utilities Reports, Inc. 2006)).

[237] Roger A. Morin, New Regulatory Finance 146 (Public Utilities Reports, Inc. 2006).

[238] *Id.* at 159.

[239] *See* Roger A. Morin, New Regulatory Finance 151-152 (Public Utilities Reports, Inc. 2006) ("the yield on very long-term government bonds, namely, the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM and Risk Premium methods.").

contrary, we find 30-year Treasury bond yields to be an appropriate basis for the risk-free rate in the NETOs' CAPM analysis.

115. We also disagree with Petitioners' argument that the NETOs' CAPM study does not support placing the NETOs' base ROE above the midpoint because the study relies on betas. Petitioners' assertion is based on a misinterpretation of Commission precedent. While Petitioners correctly state that the Commission in *ITC Holdings* and *Consumers Energy Co.* found that "betas, *in isolation*, [are] unreliable predictors of risk,"[240] Petitioners ignore the qualifier "in isolation," which highlights an important distinction between the CAPM analyses at issue in those cases and the NETOs' CAPM analysis. In both *ITC Holdings* and *Consumers Energy Co.*, the parties submitted CAPM studies that analyzed only the utility whose rates were at issue. As the Commission explained in *Consumers Energy Co.*, "CAPM is more appropriately used for determining the composition of a portfolio of stocks."[241] In the instant proceeding, the NETOs' CAPM study analyzed, as a portfolio, a proxy group of electric utilities. Thus, the NETOs' CAPM study and associated use of betas do not raise the same concerns as did the studies in *ITC Holdings* and *Consumers Energy Co*.

116. We further disagree with EMCOS's argument that the NETOs' CAPM analysis is not forward-looking because it relies on betas. As explained above, whether a CAPM analysis is forward-looking or backward-looking depends on how the market risk premium—not the betas—are calculated.[242] Although it is true that betas are based on historical data, reliance on betas does not render a CAPM analysis backward-looking, as that term is commonly used in the CAPM context. As explained above, a CAPM study is backward-looking if its market risk premium component is determined based on historical, realized returns,[243] and a CAPM study is forward-looking if its market risk premium component is based on a DCF study of a large segment of the market.[244] Unlike the market risk premium component of the CAPM methodology, betas are necessarily

---

[240] *ITC Holdings Corp.*, 121 FERC ¶ 61,229 at P 43 (emphasis added); *Consumers Energy Co.*, 85 FERC ¶ 61,100 at 61,362 (emphasis added).

[241] *Consumers Energy Co.*, 85 FERC ¶ 61,100 at 61,362 n.26 (noting Trial Staff's testimony that, according to Value Line, beta should not be used to determine the ROE for a single company).

[242] *See supra* P 108.

[243] Roger A. Morin, New Regulatory Finance 155-156 (Public Utilities Reports, Inc. 2006).

[244] *Id.* at 159-160.

based on historical data, because "[t]he true beta of a security can never be observed."[245] Therefore, we disagree with EMCOS's assertion that the use of betas renders a CAPM analysis backward-looking. We reiterate that a CAPM study is forward-looking, notwithstanding its use of betas, if its market risk premium component is based on an appropriate DCF study.

117. We disagree with Petitioners' argument that the NETOs' CAPM analysis is flawed due to the fact that the NETOs applied a size adjustment to account for the difference in size between the NETOs and the dividend-paying companies in the S&P 500. This type of size adjustment is a generally accepted approach to CAPM analyses,[246] and we are not persuaded that it was inappropriate to use a size adjustment in this case. The purpose of the NETOs' size adjustment is to render the CAPM analysis useful in estimating the cost of equity for companies that are smaller than the companies that were used to determine the market risk premium in the CAPM analysis. While Petitioners assert that the record shows that smaller firms have lower growth,[247] Petitioners' assertion rests on a comparison of companies *within* the S&P 500—all of which have large market capitalization—rather than a comparison of the S&P 500 companies to companies smaller than the S&P 500 companies. While it may be true that larger dividend-paying members of the S&P 500 are growing faster than the smaller dividend-paying members of the S&P 500, this does not indicate how the growth rates of the dividend-paying members of the S&P 500 compare to the NETOs or to other groups of companies with smaller market capitalization (e.g., the companies in either the S&P 400, which consists of companies with mid-capitalization, or the S&P 600, which consists of companies with small capitalization). Further, Petitioners' assertion is contradicted by other record evidence indicating, and supporting the generally accepted principle,[248] that smaller firms are riskier than larger firms, and therefore experience faster growth.[249]

118. Petitioners also argue that the Commission erred in ignoring Complainants' CAPM study, which indicated a 7.5 percent cost of equity, and Trial Staff's CAPM study, which indicated an 8.2 percent cost of equity. However, we find both Complainants' and

---

[245] *Id.* at 79.

[246] *Id.* at 187.

[247] Petitioners Request for Rehearing at 41 (citing Ex. SC-514).

[248] Roger A. Morin, New Regulatory Finance 187 (Public Utilities Reports, Inc. 2006).

[249] *See* Ex. NET-300 at 68 (citing *Morningstar*, "Ibbotson SBBI 2012 Valuation Yearbook," at 85).

Trial Staff's CAPM studies to be flawed. Complainants did not determine the market risk premium by using a DCF study to determine the required return on the overall market and then subtracting the risk-free rate from the DCF result, but instead estimated the market risk premium directly, using market risk premium studies. This approach is acceptable, in theory, as it is a valid method of determining market risk premium; however, it is not clear that Complainants executed the approach as a forward-looking analysis. While Complainants' approach is purportedly forward-looking, it is not clear from the record that their estimated market risk premium is, in fact, based on prospective data. Complainants used a market risk premium of 5.00 percent,[250] which appears to be determined using market risk premium data based on a mix of historical, prospective, and survey approaches.[251] While the record is not clear about how Complainants used these three categories of market risk premium studies to determine the market risk premium, if Complainants' market risk premium is based on a compilation of the three categories we do not consider the resulting market risk premium to be forward-looking. Further, even assuming *arguendo* that Complainants relied only on the prospective market risk premium studies, we are not persuaded that their CAPM study is sufficiently representative of the capital market conditions during this proceeding, as—importantly—all but one of the prospective studies listed in Complainants' exhibit pre-date the Great Recession.[252]

119. We find Trial Staff's CAPM analysis also to be flawed. Similar to Complainants' CAPM analysis, Trial Staff did not calculate the market risk premium by conducting a DCF analysis and subtracting the risk-free rate from the result, but by estimating the market risk premium directly. However, Trial Staff did not provide a study to support its estimated market risk premium,[253] and Trial Staff based its CAPM analysis on only 20 companies. Further, those 20 companies are members of the NETOs' proxy group. Because the purpose of the CAPM methodology is to calculate the cost of equity using a risk-return relationship based entirely on market risk,[254] the index of companies used in determining the market risk premium must be large enough to capture the market risk.[255]

---

[250] Ex. SC-112 at 1.

[251] *Id.* at 4-6.

[252] *Id.* at 5-6.

[253] *See* Ex. S-1 at 98.

[254] Roger A. Morin, New Regulatory Finance 145-146 (Public Utilities Reports, Inc. 2006).

[255] *Id.* at 159-160.

We do not consider a group of 20 companies, all of comparable risk, sufficiently large or diverse to accurately reflect the risks of the market as a whole, and we are therefore not persuaded that such a group accurately reflects the market risk premium to be used in a CAPM study. In addition, we note that, unlike the NETOs, neither Complainants nor Trial Staff updated their CAPM studies during the hearing; as a result, the CAPM evidence provided by the NETOs represents the most recent CAPM evidence in the record. In sum, for the above reasons, we find Complainants' and Trial Staff's CAPM analyses to be unreliable as corroborative evidence in this proceeding.

f. Expected Earnings Analysis

i. Opinion No. 531

120. In Opinion No. 531, the Commission explained that the NETOs' expected earnings analysis "can be useful in validating" the ROE determination," given the expected earnings analysis's "close relationship to the comparable earnings standard that originated in *Hope*, and the fact that it is used by investors to estimate the ROE that a utility will earn in the future."[256] The Commission found the NETOs' expected earnings analysis "informative,"[257] as it produced a midpoint of 12.1 percent and a median of 10.2 percent, both of which are above the 9.39 percent midpoint produced by the Commission's DCF analysis.[258] The Commission explained that, in relying on the NETOs' expected earnings analysis, "we do not depart from our use of the DCF methodology; rather, we use the record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness established in the record by the DCF methodology."[259]

ii. Requests for Rehearing

121. Petitioners argue that the NETOs' version of an expected earnings analysis is flawed because it "attempts to forecast returns on *book* equity, rather than investor-required returns on equity purchased at above-book study-period stock prices."[260] Petitioners state that the NETOs' analysis forecasts returns on book equity because the

---

[256] Opinion No. 531, 147 FERC ¶ 61,234 at P 147.

[257] *Id.* P 146.

[258] *Id.* P 147.

[259] *Id.* P 146.

[260] Petitioners Request for Rehearing at 43.

analysis turns on the "expected earnings/book equity ratio ("r") in Value Line's five-year forecast."[261] Petitioners contend that the Commission has long rejected setting ROEs "at the rate of return investors expect [the subject utility] to earn on [book] common equity (r), rather than the market cost of common equity (k)."[262] Petitioners assert that the Commission in Opinion No. 531 failed to address this inconsistency between the NETOs' expected earnings analysis and Commission precedent.

122. Petitioners further assert that the Commission's reliance on the NETOs' expected earnings analysis was especially unreasonable in this case because, in adopting the two-step DCF methodology, the Commission discarded the "br+sv" element of the one-step DCF methodology, which placed the "r" input in proper context by factoring it with other components of utility firm growth. Petitioners contend that, although the record contained the necessary data for the NETOs to place their "r" input in the appropriate context, the NETOs' expected earnings analysis ignored that data and instead emphasized "more speculative and optimistic" inputs.[263] Petitioners argue that the Commission in *Kern River Gas Transmission Co.*, Opinion No. 486, 117 FERC ¶ 61,077 (2006) (Opinion No. 486) held that dividends and payout ratios "should be considered in order to account for going-concern utilities' need to reinvest earnings instead of paying them all to shareholders;" however, Petitioners assert that the NETOs' have failed to do so.

123. Petitioners argue that, by relying on forecasted returns on book equity, rather than forecasted returns on the market cost of equity, the NETOs' expected earnings analysis ignores the market/book ratios of the proxy companies, which range from about 1.0 to 2.3.[264] Petitioners assert that, as a result, the NETOs' approach "simply reflects the perpetuation of a high market/book ratio, as was rejected in *Orange & Rockland*."[265] Petitioners also contend that the midpoint of the NETOs' expected earnings analysis is particularly unreliable because it was skewed upwards by Dominion's "unusually high earnings/book equity projection . . . which in turn reflected Dominion's exceptionally high market/book ratio."[266] Petitioners argue that the Commission's precedent on the use of midpoints in a cost of equity study is confined to DCF studies, and should not be used

---

[261] *Id.* at 42-43.

[262] *Id.* at 43 (citing *Orange & Rockland*, 44 FERC ¶ 61,253 at 61,952).

[263] *Id.* at 44.

[264] *Id.*

[265] *Id.*

[266] *Id.* at 44-45.

in the context of the NETOs' expected earnings analysis because relying on a midpoint value that is distorted by a high market-to-book ratio would not help reveal the market cost of equity.[267] Petitioners contend that, if the Commission does give weight to the NETOs' expected earnings analysis, the NETOs' analysis "points no higher than its median result, which was 10.2 percent."[268]

124. EMCOS argue that the NETOs' expected earnings analysis fails to recognize the critical link that "when actual or forecasted earnings are considered as a guide to an appropriate ROE allowance, they must be evaluated in conjunction with actual or forecasted stock prices."[269] EMCOS further argue that Opinion No. 531 adopted and relied upon the NETOs' expected earnings analysis without addressing any of the concerns raised by Trial Staff or Complainants. For example, EMCOS note that Trial Staff argued that the NETOs' analysis "inappropriately relies on accounting return results, which are not reflective of the market's required return as indicated by actual equity stock investors."[270] In addition, EMCOS note that the Complainants raised concerns that the NETOs' analysis included several flaws that rendered it unreliable and "overly optimistic."[271] EMCOS argue that failure to address these arguments is the definition of arbitrary and capricious decision-making.[272]

iii. <u>Commission Determination</u>

125. A comparable earnings analysis is a method of calculating the earnings an investor expects to receive on the book value of a particular stock. A comparable earnings analysis can be based either on the stock's historical earnings on book value, as reflected on the company's accounting statements, or on forward-looking estimates of earnings on book value, as reflected in analysts' earnings forecasts for the company. The latter approach is often referred to as an "expected earnings analysis" and is the approach the NETOs used in conducting their comparable earnings analysis in this proceeding. Petitioners' and EMCOS's argue that the NETOs' expected earnings analysis is flawed and does not support the Commission's decision to place the NETOs' base ROE above

---

[267] *Id.* at 45.

[268] *Id.* at 42.

[269] EMCOS Request for Rehearing at 24 (citing Ex. No. EMC-3 at 8:15-18).

[270] *Id.* at 24-25 (citing Trial Staff Initial Brief at 60).

[271] *Id.* (citing Complainants Initial Brief at 62).

[272] *Id.* at 25 (citing *Ill. Pub. Telecomm. Ass'n v. FCC,* 117 F.3d at 564).

the midpoint of the zone of reasonableness produced by the Commission's DCF analysis. We disagree.

126. The NETOs conducted their expected earnings analysis by using the return on book equity that *Value Line* forecasted for the national group of companies that *Value Line* lists as Electric Utilities. The NETOs then multiplied each of those forecasted returns by an adjustment factor to determine each utility's average return, rather than its year-end return, explaining that using the year-end return would understate actual returns because of growth in common equity over the year.[273] We consider the NETOs' expected earnings analysis to be sound, as it is forward-looking, based on a reliable source of earnings data, and appropriately converts the proxy companies' earnings to reflect average returns.[274]

127. While Petitioners correctly state that the Commission in *Orange & Rockland* rejected a proposal that "would, in effect, set the allowed rate of return on common equity at the rate of return investors expect [the utility] to earn on common equity (r), rather than the market cost of common equity (k)," that precedent is inapposite to this case for two reasons. First, *Orange & Rockland* did not involve a comparable earnings analysis; it involved a proposal to alter the DCF model by adjusting the dividend yield to reflect the expected earnings of the company whose rates were at issue, i.e., Orange & Rockland. Specifically, Orange & Rockland proposed to calculate the dividend yield in its DCF study by dividing dividend payments by book value, instead of by a current stock price. By comparison, the NETOs have not proposed to alter the DCF model to reflect expected earnings, but rather submitted an expected earnings study based on a national proxy group of utilities whose risk profiles are comparable to the NETOs.

128. Second, *Orange & Rockland* is inapposite because the Commission in that case rejected a proposal that would have had the effect of *setting* Orange & Rockland's base ROE at Orange & Rockland's own expected return on book equity. In the instant case, the Commission did not *set* the NETOs' base ROE at their own expected return on book equity or endorse an ROE analysis that would have that effect. Rather, the Commission in Opinion No. 531 used the DCF methodology to determine the NETOs' market cost of equity, and found that the NETOs' expected earnings analysis of a national proxy group was used to determine—and only relevant to—whether the midpoint of the DCF-determined zone of reasonableness provided a market cost of equity sufficient to meet the

---

[273] *See* Ex. NET-300 at 73, 32.

[274] *See, e.g.*, *S. Cal. Edison Co.*, 92 FERC ¶ 61,070 at 61,263 (finding it necessary to adjust Value Line's forecasted returns on book equity to reflect average returns rather than year-end returns); *see also* Roger A. Morin, New Regulatory Finance 305-306 (Public Utilities Reports, Inc. 2006).

requirements of *Hope* and *Bluefield*. The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's market cost of equity, because those returns on book equity help investors determine the opportunity cost of investing in that particular utility instead of other companies of comparable risk. Such a calculation is consistent with the requirement in *Hope* that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[275] As the NETOs' expert witness explained at trial, investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms.[276]

129. Investors rely on both the market cost of equity and the book return on equity in determining whether to invest in a utility, because investors are concerned with both the return the regulator will allow the utility to earn *and* the company's ability to actually earn that return.[277] If, all else being equal, the regulator sets a utility's ROE so that the utility does not have the opportunity to earn a return on its book value comparable to the amount that investors expect that other utilities of comparable risk will earn on their book equity, the utility will not be able to provide investors the return they require to invest in that utility.[278] Thus, all else being equal, an investor is more likely to invest in a utility that it expects will have the opportunity to earn a comparable amount on its book equity as other enterprises of comparable risk are expected to earn. Because investors rely on expected earnings analyses to help estimate the opportunity cost of investing in a particular utility, we find this type of analysis useful in corroborating whether the results produced by the DCF model may have been skewed by the anomalous capital market conditions reflected in the record.

130. We also reject Petitioners' argument that it was unreasonable for the Commission to rely on the NETOs' expected earnings analysis without also considering the "br+sv" formula in the Commission's DCF analysis. Whether "r" is directly used in the Commission's calculation of the short-term growth rate in the DCF methodology does not bear on the validity of the NETOs' expected earnings analysis or on its relevance in

---

[275] *Hope*, 320 U.S. at 603; *see also Petal Gas Storage, L.L.C.*, 496 F.3d 695 (D.C. Cir. 2007).

[276] Ex. No. NET-300 at 71.

[277] *See* Tr. 637:6-12.

[278] As the NETOs' witness testified, returns on book value are analogous to the allowed return on a utility's rate base. *Id.*

corroborating the results of the Commission's DCF analysis.[279] As explained below, the expected earnings analysis and DCF analysis are used to estimate two different types of returns, each valid in its own right, that investors rely upon in determining whether to invest in a particular company.[280]

131. As to the argument that the midpoint of the NETOs' expected earnings analysis is skewed upwards by the results of one company, i.e., Dominion, Petitioners conclusory statements that Dominion's expected earnings are "unusually high" and that Dominion's market-to-book ratio is "exceptionally high" are insufficient to show that Dominion's results skewed the NETOs' analysis. Petitioners state that Dominion has a market-to-book ratio of 2.255, that this value skewed the result of the NETOs' expected earnings analysis, and that there is no evidence that the NETOs have market-to-book ratios comparable to Dominion's.[281] However, Petitioners have provided no evidence demonstrating that Dominion's 2.255 market-to-book ratio is "exceptionally high," and there is no evidence that the NETOs' market-to-book ratios are not comparable to those of the proxy group companies. Lastly, even assuming *arguendo* that it would be more appropriate to eliminate Dominion or to use the median, rather than the midpoint, of the NETOs' expected earnings analysis, the result would be 11.2 percent or 10.2 percent, respectively. Both of these results are above the 9.39 percent midpoint of the DCF-produced zone of reasonableness and, therefore, corroborate the Commission's decision to place the NETOs' base ROE above the 9.39 percent midpoint.

132. While Petitioners and EMCOS[282] assert that the NETOs' expected earnings study ignores the proxy companies' market-to-book ratios, considering market-to-book ratios in an expected earnings study is inconsistent with the purpose of the comparable earnings model. The comparable earnings model is intended to estimate the return on book equity

---

[279] We also reject Petitioners' assertion that Opinion No. 486 is relevant to the validity of the NETOs' expected earnings analysis. The language from Opinion No. 486 to which Complainants cite does not involve an expected earnings analysis; rather it concerns whether it is appropriate to base the dividend yield in a DCF analysis of a master limited partnership on its earnings, rather than on dividend payments in excess of earnings. *See* Opinion No. 486, 117 FERC ¶ 61,077 at P 153.

[280] *See infra* P 132.

[281] Petitioners Request for Rehearing at 44-45.

[282] EMCOS argue that the NETOs' expected earnings analysis is flawed because it does not evaluate forecasted earnings in conjunction with forecasted stock prices. This is merely another way of saying that the NETOs' expected earnings analysis failed to consider market-to-book ratios.

that investors expect the *utility* will earn; the market cost of equity, by comparison, is the estimated return to *investors* that an investor requires to invest in the utility. Petitioners and EMCOS seek to adjust the estimated return on book equity produced by the NETOs' expected earnings analysis into the market cost of equity, by applying a market-to-book adjustment. However, as noted above, the return on book equity is relied upon by investors to determine the opportunity cost of investing in a particular company, and investors rely upon expected earnings analysis for this purpose without attempting to convert that opportunity cost into the market cost of equity. We, therefore, find the NETOs' expected earnings analysis reliable as corroborative evidence in this proceeding, notwithstanding the lack of a market-to-book adjustment in that analysis. Further, even assuming *arguendo* that a market-to-book adjustment was appropriate, we are not persuaded that Petitioners' approach of simply dividing a utility's book return on equity by its market-to-book ratio would accurately estimate the utility's market cost of equity. We also disagree with EMCOS's argument that the NETOs' expected earnings analysis relies on accounting return results, and is therefore not corroborative of the market cost of equity. As noted above, the NETOs' expected earnings analysis is based on forecasted earnings, not historical returns reflected on accounting statements.

3. Impact of the DCF Methodology Change on Existing ROE Transmission Incentive Adders

a. Opinion No. 531

133. Opinion No. 531 explained that, "[b]ased on the Commission's policy that the total ROE including any incentive ROE is limited to the zone of reasonableness, the Commission has found in the past that an incentive ROE may not be implemented in full by the utility if the total ROE exceeds the zone of reasonableness."[283] The Commission found that "[n]othing in [Opinion No. 531] changes this Commission policy,"[284] and, therefore, "when a public utility's ROE is changed, either under section 205 or section 206 of the FPA, that utility's total ROE, inclusive of transmission incentive ROE adders, should not exceed the top of the zone of reasonableness produced by the two-step DCF methodology."[285]

---

[283] Opinion No. 531, 147 FERC ¶ 61,234 at P 164.

[284] *Id.*

[285] *Id.* P 165.

b. Request for Rehearing

134. The NETOs request that the Commission clarify that adjustments to the NETOs' ROE incentive adders are outside the scope of this proceeding.[286] The NETOs state that the base ROE was the sole matter set for hearing, no party submitted evidence relating to incentive adders, and the issue was not discussed in the Initial Decision.[287] The NETOs assert that Opinion No. 531 does not state with specificity that the NETOs' total ROE must not exceed the top of the zone of reasonableness, and the NETOs interpret the Commission's language concerning capping the total ROE as a statement of a general ratemaking principle.[288]

135. If the Commission did intend to require the NETOs to reduce the total ROE to the top of the zone of reasonableness, the NETOs request rehearing of that decision. The NETOs state that the "ROE incentive adders were approved based upon a detailed record of the benefits and risks of the relevant projects and the nexus between the incentive adders and the projects, which included consideration of the ability of the incentive to facilitate construction of the project."[289] The NETOs state that, when the adders were approved, they were below the top end of the then-current zone of reasonableness. The NETOs argue that the Commission placed no conditions on the adders' continued effectiveness, and that the adders do not automatically change when the Commission determines a new zone of reasonableness.[290]

136. The NETOs state that the base ROE was the only matter at issue in this case, and that incentive adders were explicitly excluded by the complaint.[291] The NETOs argue that modifying the incentive adders in this proceeding would violate the Constitution's Due Process Clause and the Administrative Procedure Act.[292] The NETOs state that, in a similar case, the Commission granted an ROE adder without notice to the parties that the issue would be decided during the hearing and the D.C. Circuit found that the

[286] NETOs Request for Rehearing at 6-7.

[287] *Id.* at 7-8.

[288] *Id.* at 8-9.

[289] *Id.* at 11-12.

[290] *Id.* at 13.

[291] *Id.* at 14-15.

[292] *Id.* at 15-16.

Commission had violated the parties' due process rights.[293] The NETOs state that, in each of the cases that the Commission cited in Opinion No. 531, the ROE incentive adders were implicated prior to the hearing, thus providing the parties with notice and the opportunity to submit evidence on the incentive adders. The NETOs assert that, assuming the Hearing Order had addressed incentive adders, the Commission erred in ruling that the adders must be reduced without accepting evidence on the issue.[294]

137. The NETOs request that the Commission clarify that the term "total ROE" refers to the total transmission assets of a utility rather than project-specific ROEs.[295] The NETOs argue that as long as the ultimate rate charged to consumers is just and reasonable, FPA section 219 is satisfied and the Commission has no basis to look at project-specific ROEs to determine whether they are below the top of the zone of reasonableness.[296]

138. The NETOs argue that, if the term "total ROE" includes incentive ROEs, Opinion No. 531 should be reversed as inconsistent with statutory requirements and Commission precedent. The NETOs state that in Order No. 679 the Commission stated that the test for reviewing a rate is whether the end result is reasonable.[297] The NETOs argue that such an evaluation necessarily involves review of the overall rate inclusive of all components, not merely a review of one component such as an individual project's incentive ROE.[298]

c. Commission Determination

139. We deny rehearing on this issue. As an initial matter, it is worth noting that Opinion No. 531 does not change the incentive ROE adders that the Commission previously granted to the NETOs. Rather, Opinion No. 531 follows Commission policy that a utility's ROE, even if it includes an incentive ROE adder, would be capped at the

---

[293] *Id.* at 17-18 (citing *PSC of Kentucky*, 397 F.3d at 1011-12).

[294] *Id.* at 18-20.

[295] *Id.* at 20-22.

[296] *Id.* at 22-23.

[297] *Id.* at 23-24.

[298] *Id.* at 24-26 (citing *Northeast Utils. Serv. Co.*, 52 FERC ¶ 61,097 (1990), *reh'g denied*, 52 FERC ¶ 61,336; *Florida Power & Light Co.*, 24 FERC ¶ 61,171, at 61,408 (1983); *Florida Power & Light Co.*, 32 FERC ¶ 61,059 at 61,162 (1985)).

upper end of the transmission owner's DCF-determined zone of reasonableness. For example, in Order No. 679, the Commission made clear that the total ROE including any incentive ROE adder sought by an applicant must be within the utility's DCF-determined zone of reasonableness.[299] In the orders in which the Commission granted the NETOs' incentive ROE adders, the Commission also made clear that the total ROE including such adders would be capped at the high end of the NETOs' zone of reasonableness.[300] The fact that a transmission owner may not be able to implement in full its awarded incentive ROE adder because the resulting total ROE would exceed the high end of the transmission owner's zone of reasonableness is nothing new.[301] In addition, the

---

[299] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, at PP 2, 93 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007); *Pac. Gas & Elec. Co.*, 141 FERC ¶ 61,168, at P 26 (2012); *see also Town of Norwood, Mass. v. FERC*, 80 F.3d at 534-535 (supporting the principle that ROE should be cabined within the bounds of the zone of reasonableness, by reversing a Commission decision to set ROE at the bottom of the zone of reasonableness that was established in the utility's prior rate case and explaining that the Commission cannot rely on a zone of reasonableness established in a prior rate case if the utility's circumstances have since changed); 16 U.S.C. § 824s(d) (2012) ("All rates approved under the rules adopted pursuant to [FPA section 219] . . . are subject to the requirements of sections [205 and 206] of this title that all rates . . . be just and reasonable."); Order No. 679-A, FERC Stats. & Regs. ¶ 61,236 at P 15 (cross-referenced at 117 FERC ¶ 61,345 at P 15) (indicating that the Commission will keep any incentive ROE adder within the zone of reasonableness as a means to ensure the Commission comply with its regulatory responsibilities under the FPA). The courts have also recognized that utilities cannot charge rates that exceed the DCF-determined zone of reasonableness. *See, e.g.*, *Union Elec. Co. v. FERC*, 890 F.2d 1193, 1204 (D.C. Cir. 1989).

[300] *See, e.g.*, *Ne. Utils. Serv. Co.*, 124 FERC ¶ 61,044 at P 83.

[301] *See, e.g.*, *NSTAR Elec. Co.*, 125 FERC ¶ 61,313 at PP 81-87 (granting a New England transmission owner an incentive ROE adder, to be bound by the upper end of the zone of reasonableness previously established for the New England transmission owners; and determining, based on an updated DCF analysis, that the overall ROE including the incentive ROE adders remained within the zone of reasonableness); *accord Me. Pub. Utils. Comm'n v. FERC*, 454 F.3d at 288-89 (affirming the Commission's decision to grant transmission owners that join ISO New England a 50 basis point incentive ROE adder for RTO participation, and the Commission's decision to cap the overall ROE at the top of the zone of reasonableness); *Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid*, 102 FERC ¶ 61,032, at P 37 (2003) (noting that, in implementing ROE-based incentives, including the RTO

(continued…)

Commission has summarily applied this policy in rate cases initiated after an ROE adder was approved. For example, in establishing a hearing on a section 205 rate filing by Pacific Gas and Electric Co. (PG&E), the Commission held that a 200 basis point adder originally granted to PG&E ten years earlier[302] and a 50 basis point ROE adder for RTO participation granted two years earlier[303] would be limited to within the new zone of reasonableness determined at the hearing.[304] Thus, whether the merits of a utility's incentive ROE adders are implicated by a proceeding is a much different issue than whether the utility can fully implement its incentive ROE adders due to changes in the zone of reasonableness for that utility. This proceeding involves only the latter of these two issues; it does not involve the merits of the NETOs' existing incentive ROE adders.

140. Contrary to the NETOs' assertion, the Commission's ruling in Opinion No. 531 on this issue was not merely a general statement of ratemaking principle, it was a continuation of a Commission policy that the NETOs' total ROE cannot exceed the zone of reasonableness calculated in this proceeding.[305]

141. The NETOs argue that the precedent cited by Opinion No. 531 concerning ROE incentive adders, such as *PG&E*, is distinguishable from the instant proceeding because in the incentives cases the incentives were implicated before the hearing, and the parties therefore had notice and opportunity to submit evidence on the issue. We disagree. In the cases cited by Opinion No. 531, the Commission did not set for hearing the issue of whether an existing incentive adder should be reduced to no higher than the top of the

---

participation adder, those incentives would be subject to a cap on the overall ROE equal to the top of the range of reasonable ROEs for a proxy group).

[302] *See Western Area Power Admin.*, 100 FERC ¶ 61,331, at PP 12-13 (2002).

[303] *Pac. Gas & Elec. Co.*, 132 FERC ¶ 61,272, at P 23 (2010).

[304] *PG&E*, 141 FERC ¶ 61,168 at P 26 (continuing to grant a 200 basis point ROE adder for the PATH 15 upgrade project, granted prior to Order No. 679, and a 50 basis point adder for RTO participation, granted subsequent to Order No. 679, and in doing so "remind[ing] PG&E that any ROE adder is limited to within the range of reasonableness of the ROE.").

[305] This is reaffirmed by the Commission's determination in Opinion No. 531-A, the order on the paper hearing that the Commission established in Opinion No. 531, in which the Commission found that the zone of reasonableness produced by the DCF methodology in this proceeding is 7.03 percent to 11.74 percent and, therefore, that "the NETOs' total or maximum ROE, including transmission incentive ROE adders, cannot exceed 11.74 percent." Opinion No. 531-A, 149 FERC ¶ 61,032 at P 11.

new zone of reasonableness. Rather, the Commission summarily ruled on that issue before the hearing. Because the Commission has an established policy that incentive adders must be within the zone of reasonableness in order to comply with section 219(a) of the FPA, the issue of whether to reduce an incentive adder that would otherwise exceed the top of the zone of reasonableness does not present any issue of material fact that would be appropriate for consideration in a hearing.

142. In any event, the NETOs' did in fact have notice and opportunity to present argument on the issue of their total ROE. Because it is well established both that a proceeding to determine a utility's base ROE involves a determination of the utility's zone of reasonableness under the DCF methodology, and that a transmission owner's awarded incentive ROE adder could not exceed the high end of the zone of reasonableness, the NETOs had notice to present evidence regarding the zone and thus the ultimate just and reasonable total ROE.

143. We disagree with the NETOs' argument that *PSC of Kentucky*, 397 F.3d 1004, is relevant to this issue. That case involved the Commission's post-hearing decision to grant an incentive ROE that the Commission, in setting the case for hearing, explicitly declined to grant and stated would not be at issue in the proceeding. Those facts are distinguishable from the facts here.

144. In *PSC of Kentucky*, the court found that the Commission violated the parties' due process rights because the Commission, having initially determined that it would not grant an incentive ROE adder, at the end of the proceeding granted the incentive ROE adder, and thus failed to place the parties on notice at the outset that, post-hearing, its order might grant the incentive ROE adder.[306] The court explained that, while the Commission considered the petitioners' arguments regarding the incentive ROE adder on rehearing, the Commission did not allow them to present evidence at hearing on the relevant factual issue, i.e., the need for, or appropriate size of, the incentive ROE adder.[307] In contrast, here the parties had both opportunities to make their case. The NETOs had notice of the Commission's already-well-established policy that a utility's total ROE must remain within the zone of reasonableness identified by the DCF analysis, and the NETOs had the opportunity to submit—and did, in fact, submit—evidence at hearing on the relevant factual issue, i.e., the zone of reasonableness identified by the

---

[306] *PSC of Kentucky*, 397 F.3d at 1012.

[307] *Id.*

DCF analysis. Further, they also have had the opportunity to raise their arguments concerning this issue on rehearing.[308]

145. The NETOs assert that the Commission's use of the term "total ROE" in Opinion No. 531 may be read to refer only to "the overall ROE of the utility (inclusive of all transmission assets), rather than project-specific ROEs," because the Commission did not "address the meaning of 'total ROE' in the context of a multiple-asset utility."[309] Contrary to the NETOs' assertion, Opinion No. 531 did address the meaning of the term "total ROE" both in the context of ROEs that apply to specific projects[310] and in the context of ROEs that apply to multiple utility assets.[311] To be clear, the term "total ROE" applies to, and has identical meaning in, both contexts. Requests for incentive ROE adders are typically presented to the Commission in one of three ways: (1) a request for incentive ROE adders that apply to all of a utility's transmission assets;[312] (2) a request for incentive ROE adders that apply only to specific transmission projects;[313] or (3) a request for a combination of incentive ROE adders, some of which apply to all of the utility's transmission assets and some of which apply only to specific transmission projects.[314] In each type of incentive ROE case, the Commission has explained that the total ROE, i.e., the base ROE plus any incentive adders, for the transmission assets to which the adder applies is capped at the top of the zone of reasonableness.[315] In other

---

[308] *See, e.g.*, *State of Cal. ex rel. Lockyer v. FERC*, 329 F.3d 700, 711 (2003) ("the Commission provided all the procedural protections required by the Fifth Amendment and FPA when it carefully considered all the evidence and arguments that the petitioners offered in their petitions for rehearing and motions to intervene."); *see also ANR Pipeline Co. and TC Offshore LLC*, 143 FERC ¶ 61,225, at PP 57, 60 (2013).

[309] NETOs Request for Rehearing at 20-21.

[310] Opinion No. 531, 147 FERC ¶ 61,234 at P 164 (citing *Trans Bay Cable LLC*, 145 FERC ¶ 61,151 (2013), and *Atlantic Path 15, LLC*, 135 FERC ¶ 61,037 (2011)).

[311] *Id.* (citing *PG&E*, 141 FERC ¶ 61,168).

[312] *See, e.g.*, *Oklahoma Gas & Elec. Co.*, 122 FERC ¶ 61,071 (2008).

[313] *See, e.g.*, *NSTAR Elec. Co.*, 125 FERC ¶ 61,313; *see also RITELine Illinois, LLC & RITELine Indiana, LLC*, 137 FERC ¶ 61,039 (2011).

[314] *See, e.g.*, *PG&E*, 141 FERC ¶ 61,168.

[315] *See, e.g.*, *Oklahoma Gas & Elec. Co.*, 122 FERC ¶ 61,071 at P 36 n.26; *NSTAR Elec. Co.*, 125 FERC ¶ 61,313 at P 81; *PG&E*, 141 FERC ¶ 61,168 at P 26.

words, incentive ROE adders are capped by the top of the DCF-determined zone of reasonableness, regardless of the particular incentive ROE adder authorized or the transmission assets to which it applies. This is appropriate because all incentives ultimately must be evaluated according to the same methodology, i.e., they must be evaluated against a zone of reasonableness above which the record does not support the total ROE including any incentive ROE adders as just and reasonable.

146. We also reject the NETOs' argument that FPA section 219 is satisfied, and the Commission has no basis to change a project-specific ROE, as long as the utility's ultimate rate is just and reasonable. This argument is inconsistent with the Commission's precedent on project-specific ROE incentives, in which the Commission has held that the utility's total ROE for the project cannot exceed the zone of reasonableness.[316] In addition, the practical effect of the NETOs' argument—"even if an incentive ROE for a particular project exceeds a utility's zone of reasonableness, so long as the entire utility's ROE (inclusive of all transmission assets) falls within the utility's zone of reasonableness, no change would be needed to the project-specific incentive ROE"—appears to result in incentive ROE adders applying to facilities to which the Commission has not granted the adders. An incentive ROE adder may not serve to increase the ROE for a transmission asset that has not been granted an incentive. Lastly, we disagree with the NETOs that *Northeast Utilities Service Co.*, 52 FERC ¶ 61,097 (1990), *Florida Power & Light Co.*, 24 FERC ¶ 61,171 (1983), and *Florida Power & Light Co.*, 32 FERC ¶ 61,059 (1985), support allowing project-specific ROEs above the zone of reasonableness. Those cases did not involve an analysis of the utilities' ROE relative to the zone of reasonableness produced by a DCF methodology; rather, those cases involved analyses of the equity returns at issue relative to either the utilities' costs[317] or to other rate designs that the utility could have used.[318]

4. <u>Establishment of a Just and Reasonable Rate</u>

a. <u>Opinion No. 531</u>

147. The Commission in Opinion No. 531 did not establish the NETOs' just and reasonable ROE. As the Commission explained, the "finding concerning the specific numerical just and reasonable ROE for the NETOs is subject to the outcome of the paper

---

[316] *See, e.g.*, *Pepco Holdings, Inc.*, 125 FERC ¶ 61,130, at PP 75-79, 91-94 (2008).

[317] *See Florida Power & Light*, 24 FERC ¶ 61,171 at 61,408; *Florida Power & Light Co.*, 32 FERC ¶ 61,059 at 61,162.

[318] *See Northeast Utils. Serv. Co.*, 52 FERC ¶ 61,097 at 61,485-486.

hearing on the appropriate long-term growth projection to be used in the two-step DCF methodology."[319]

b. Requests for Rehearing

148. EMCOS requests that the Commission clarify that it intended for Opinion No. 531 to establish 10.57 percent as the prospective base ROE in effect from the date of issuance of Opinion No. 531, pending the outcome of the paper hearing on the long-term growth rate for use in the two-step DCF methodology. Similarly, Petitioners argue that the Commission erred by not directing the NETOs to prospectively reduce their rates as of June 19, 2014, based on the tentative findings in Opinion No. 531.[320] Petitioners also argue that it was arbitrary and inconsistent with the section 206 "bond of protection" for the Commission to rely on the 4.39 percent long-term growth rate for purposes of excluding PSEG, while not relying on a 4.39 percent second-step growth rate for purposes of setting an interim or final ROE to be observed.[321]

149. Petitioners assert that the paper hearing is unlikely to materially alter the conclusions reached in Opinion No. 531 and that any refinement of the NETOs' ROE could be implemented as a refund or surcharge against the 10.57 percent base ROE. Petitioners argue that FPA section 206 requires the Commission to fix the rate to be observed as of the date of Opinion No. 531.[322] Petitioners further argue that courts have found that the Commission has "fixed" a rate when parties are in a position to supply their own inputs to a formula and thereby know the numerical rates. Petitioners contend that Opinion No. 531 provides such a formula by supplying a 10.57 percent base ROE and an 11.74 percent maximum ROE.[323]

150. Petitioners argue that implementing interim rates is required by the Commission's obligation to "act as speedily as possible" on FPA section 206 complaints.[324] Petitioners

---

[319] Opinion No. 531, 147 FERC ¶ 61,234 at P 152.

[320] Petitioners Request for Rehearing at 66 (citing *New England Power Generators Association v. ISO New England Inc.*, 146 FERC ¶ 61,038, at P 26 (2014); *Georgia Power Co.*, 57 FERC ¶ 61,353 (1991)).

[321] *Id.* at 61-62.

[322] *Id.* at 69-70.

[323] *Id.* at 70-71.

[324] *Id.* at 71 (quoting 16 U.S.C. § 824e(b)).

state that, as an alternative to making the NETOs' new ROE prospectively effective as of June 19, 2014, the Commission could direct the NETOs to use the final ROE in its true-up calculation for the 2014 rate year.[325] Petitioners note that if the Commission uses this alternative method, the Commission must issue its order on the paper hearing before July 31, 2015 to ensure that the true-up filing is implemented with the correct ROE.[326]

c. Commission Determination

151. We deny Petitioners' and EMCOS's requests to prospectively establish the NETOs' replacement rate as of June 19, 2014.[327] FPA section 206 requires that "[w]henever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate . . . is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate . . . to be thereafter observed and in force, and shall fix the same by order."[328] As the Commission explained in Opinion No. 531, however, its findings regarding the justness and reasonableness of the NETOs' rates were "tentative because [they were] subject to the submission of the record evidence at the paper hearing . . . as to the appropriate long-term growth rate."[329] While the appropriate long-term growth rate itself was a narrow issue, that input had the potential to materially affect the NETOs' ROE by altering the DCF results of the companies in the proxy group.[330] As a result, the Commission could not satisfy the requirement of FPA section 206 that it "fix" the just and reasonable rate to be in effect prospectively until after the paper hearing established by Opinion No. 531. Only

---

[325] *Id.* at 72 (citing *South Carolina Elec. & Gas Co.*, 132 FERC ¶ 61,043 (2010)).

[326] *Id.* at 74.

[327] The Commission established the just and reasonable ROE for the NETOs on October 16, 2014, in Opinion No. 531-A. *See* Opinion No. 531-A, 149 FERC ¶ 61,032 at PP 10-12.

[328] 16 U.S.C. § 824e (2012).

[329] Opinion No. 531, 147 FERC ¶ 61,234 at P 142.

[330] We reject Petitioners' assertion that it was inconsistent for the Commission to rely on the 4.39 percent GDP growth rate in eliminating PSEG from the proxy group as a low-end outlier and not rely on that GDP growth rate to establish a just and reasonable rate in Opinion No. 531. If the paper hearing had modified the 4.39 percent GDP growth rate, the Commission could have been required to reconsider its low-end outlier ruling based on the revised DCF results. However, the paper hearing did not change the 4.39 percent GDP growth rate and, therefore, no such reconsideration was required.

with the issuance of Opinion No. 531-A, on October 16, 2014, did the Commission establish the prospective just and reasonable rate.[331]

152. We similarly disagree with Petitioners that the Commission fixed the just and reasonable rate in Opinion No. 531 by providing a formula by which the parties could supply their own inputs and know the numerical rate. The Commission in Opinion No. 531 provided no such formula. Further, even assuming *arguendo* that the Commission's analysis could be characterized as a formula, a key input—the long-term growth rate—was unsettled pending the outcome of the paper hearing. Lastly, we reject Petitioners' request that we direct the NETOs to include the ROE established in this proceeding in their true-up calculation for the 2014 rate year. When the NETOs make the annual Regional Network Service true-up filing in 2015 to update the formula rates to reflect calendar year 2014 actual data, consistent with the requirements of the Regional Network Service formula, the filing should reflect the relevant ROEs in effect for any month within the 2014 time period. As mentioned above, the prospective effective date for the ROE determined in this proceeding is October 16, 2014, the issuance date of Opinion No. 531-A. Accordingly, Petitioners' alternative request to direct the NETOs to include the ROE determined in this proceeding for the entire 2014 calendar year is inconsistent with the effective date established in Opinion 531-A. We note that there are other complaints involving the NETOs' ROEs pending before the Commission in Docket Nos. EL13-33 and EL14-86 that may affect the ROE ultimately charged under the Regional Network Service formula for other months in 2014; however, any changes to the formula as a result of those complaints will not be effective until the Commission issues final orders in those proceedings.

The Commission orders:

(A) Petitioners', EMCOS's, and the NETOs' requests for rehearing of Opinion No. 531 are hereby denied, as discussed in the body of this order.

---

[331] *See* Opinion No. 531-A, 149 FERC ¶ 61,032. The Commission in Opinion No. 531-A also directed the NETOs to issue refunds for the 15-month refund period in this proceeding, i.e., from October 1, 2011 through December 31, 2012.

(B) The NETOs' request for rehearing of Opinion No. 531-A is hereby denied, as discussed in the body of this order.

By the Commission. Commissioner Honorable is concurring with a separate statement attached.

(S E A L)

Kimberly D. Bose,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Martha Coakley, Massachusetts Attorney General; Connecticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group v. Bangor Hydro-Electric Company; Central Maine Power Company; New England Power Company d/b/a National Grid; New Hampshire Transmission LLC d/b/a NextEra; NSTAR Electric and Gas Corporation; Northeast Utilities Service Company; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; Vermont Transco, LLC	Docket Nos. EL11-66-002 EL11-66-003

(Issued March 3, 2015)

HONORABLE, Commissioner, *concurring*:

In denying the requests for rehearing, the Commission sets forth a cogent defense of Opinion No. 531 and duly considers and adequately addresses the arguments of the petitioners in the numerous requests for rehearing. Additionally, it is within the Commission's discretion to alter the DCF methodology for determining the just and reasonable rates of return for the NETOs.

I write separately to emphasize two important points to ensure that they are not lost in the shift in the DCF methodology and the placement of the base ROE above the central tendency of the zone of reasonableness. These points relate to: (1) the determination of the just and reasonable rate; and (2) the anomalous market conditions that prompted the consideration of alternative methodologies which ultimately led to the placement of the base ROE halfway between the midpoint and the top of the zone of reasonableness.

The just and reasonable rate of return for a public utility necessarily must consider *both* the protection of the consumer and the capital attraction standards set forth in *Hope* and *Bluefield*. The Commission appropriately relies upon the landmark *Hope* and *Bluefield* decisions to make the point that the allowed return should be adequate to enable it to secure the funding necessary for the proper discharge of its public duties. The duty to ensure the NETOs' ability to attract capital prompted consideration of additional record evidence and led to the use of alternative methodologies as benchmarks against which the DCF results were measured. However, while the Commission in Opinion No. 531 tacitly recognizes that a just and reasonable rate protects consumers, it does not emphasize consumer protection as forcefully as it could have. The primary purpose of the authority granted to the Commission to ensure a just and reasonable rate is to protect the consumer.[1] Indeed, the *Hope* decision, relied upon by this Commission to articulate the just and reasonable standard, explicitly provides that the Commission must balance both "investor and consumer interests."[2] In finding that balance, the Commission dedicates significant effort to ensuring that the NETOs are able to attract sufficient capital. While capital attraction is essential, Opinion No. 531 should not be interpreted as tipping the scale in favor of investor interests. As intended by Congress and confirmed by the Courts, consumer protection is in the DNA of FERC's ratemaking authority. Opinion No. 531 does not, and cannot, change that fact.

Keeping in mind the delicate balance that the Commission must strike when weighing investor and consumer interests, it is important to note that the finding of "anomalous market conditions" in Opinion No. 531 did not create a bright line test nor did it create a presumption that market conditions will be found to be anomalous going forward. The anomalous, or unusual, market conditions that were found in the original order to justify the placement of the base ROE above the central tendency of the zone of

[1] *See, e.g., Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cnty., Wash*., 554 U.S. 527, 564 (2008) ("Congress enacted the FPA precisely because it concluded that regulation was necessary to protect consumers from deficient markets.").

[2] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

reasonableness were, by definition, atypical. Any public utility that seeks to rely upon anomalous market conditions to justify placement of its base ROE in the upper end of the zone of reasonableness will be tasked with demonstrating, in each case, that market conditions are indeed anomalous and that the adequacy of a base ROE set at the midpoint of the zone of reasonableness should be scrutinized. The utility should expect a rigorous analysis of the record when it attempts to make such a demonstration.

The decision in Opinion No. 531 is within the Commission's broad discretion to determine the just and reasonable rate. I concur with this denial of the requests for rehearing to emphasize the points discussed above.

____

Colette D. Honorable
Commissioner

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2017-00198

December 21, 2017

EMERA MAINE
Request for Approval of
Proposed Rate Increase

BENCH ANALYSIS

I. BACKGROUND

A. 2015-00360 Management Audit and Order

As part of its rate request in Docket No. 2013-00443, Emera Maine (the Company) initially estimated the cost for a new customer billing system, or "CIS," for its Bangor Hydro District (BHD) to be approximately $17.2 million. Over the course of the proceeding, the Company increased that estimate to $18.8 million, and then increased it once again to $19.6 million. The parties included the $19.6 million estimate in the stipulation that concluded the proceeding. The "in-service" date for CIS also shifted over the course of the proceeding, from an initial estimate of May 2014, to the estimate included in the stipulation in August 2014.

In the next Emera Maine rate case, initiated by the Company in Docket No. 2015-00360, the Company stated that at the time it entered into the stipulation in the prior proceeding, the estimated cost was actually $23.3 million, and not the $19.6 million specified in the stipulation. In addition, the Company stated that the actual final cost of CIS implementation was $30.9 million, with an actual in-service date of June 2015.

Subsequent to the Company's implementation of CIS, the Commission's Consumer Assistance and Safety Division (CASD) began to receive complaints from customers about billing errors. CASD had several discussions with the Company about these issues, which were, apparently, the result of CIS implementation problems. Among the CIS issues discovered by the CASD were a failure to produce or send bills; improper bill dates, including erroneous due dates; one-time fees being charged more than once; and some customers of competitive electricity providers being double-charged for state taxes. The CIS billing issues were reflected in the Company's "Bill Error" service quality index (SQI) metric for 2015: the SQI benchmark for bill errors is 0.04%; the Company's actual bill error rate for BHD was 1.69%.

Emera faced other customer service issues. During the period encompassed by the rate cases, the CASD had numerous discussions with the Company regarding:

- The Company's failure to issue refunds to customers of People's Power and Gas (People's) for improper charges by People's, despite the Commission forwarding to Emera Maine the security payment People's had placed with the Commission;
- The Company's failure to respond to Commission requests for information regarding the status of the refunds for the People's overcharges;
- A Company decision to unbundle customer charges (stranded costs and conservation) on customer bills prior to requesting a waiver of the Commission's Rules, and also significantly overstating the costs to re-bundle such charges;
- The Company's inability to stop billing customers for Competitive Electricity Provider (CEP) charges after customers had discontinued service with a particular CEP in contravention to the requirements of Chapter 322 § 3(E) of the Commission's Rules;
- The inability of the Company to identify customer-owned private lines for purposes of calculating which portion of storm restoration work done by Emera was attributable to such customers, which resulted in Emera providing refunds to all customers billed for such service; and
- Poor performance by the Company for the "Business Calls Answered in 30 Seconds" and "Service Order Timeliness" SQI metrics.

In addition, information presented to the Commission in *Maine Public Utilities Commission, Commission Initiated Investigation Into Emera Maine's Transmission Maintenance and Planning Practices,* Docket No. 2015-00161, raised concerns regarding the reliability of the Company's transmission and distribution (T&D) system;

concerns which were supported by poor performance results in the Company's System Average Interruption Frequency Index (SAIFI).

Based on these concerns, the Commission initiated a management audit of the Company. *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket No. 2015-00360, Order Initiating Management Audit (Apr. 13, 2016). In its Order Initiating Audit, the Commission stated that the purpose of the audit was to determine whether:

1. The Company's CIS System (Phase I) was planned and managed in a way that the project would come in as scheduled, on budget and in a manner that ensured that the CIS project delivered the capabilities and functionalities which would maximize ratepayer value.

2. The Company's credit and collections and customer service functions are being managed and operated in an effective, prudent and efficient manner; and

3. Whether Emera Maine's management and operation of its T&D system is being done in a manner that is effective, prudent and efficient and in a manner that ensures that its customers receive reliable service in accordance with reasonable utility management practices.

Id. at 3.

2. The Liberty Audit and Commission Conclusions

After issuing its Order Initiating Audit, the Commission released a Request for Proposals (RFP), seeking a qualified consultant to conduct the audit. The RFP specified that the audit should focus on customer service functions, T&D operation and reliability, and CIS procurement and implementation. *Emera Maine, Request for*

Approval of a Proposed Rate Increase, Docket No. 2015-00360, Final Report on an Audit of Emera Maine's Management Practices, Customer Information System, and Service Quality at I-1 (Aug. 8, 2016) (Audit Report). The Commission selected Liberty Consulting Group (Liberty) to perform the audit. *Id.*

a. Customer Service

Liberty studied ten separate areas relating to customer service: Organization and Staffing, Costs, Customer Satisfaction, Complaint Resolution, Account Creation and Management, Meter Reading and Meter Services, Billing, Payment and Collections, Contact Center Operations, and Revenue Projection. *Id.* at III-1 to III-25.

Based on its work, Liberty reached twenty-one separate conclusions regarding customer service, and made ten discrete recommendations for improvement by the Company. *Id.* at III-26 to III-41. In sum, Liberty concluded that the Company's overall customer service performance was "weak." *Id.* at I-4. Liberty stated that the Company failed to adequately staff its frontline customers service, had poor call answering performance, poor customer satisfaction, and poor employee engagement. *Id.* A review of the Audit Report indicates that the principal driver of poor customer service performance was Emera Maine's staffing levels, with the Company even lowering some of its internal customer service goals (*e.g.*, its goal of answering 80% all calls within thirty seconds) in recognition of its inability to achieve industry standard results. *Id* at I-4, III-3 to III-4, III-6. Many of Liberty's recommendations centered around improving staffing levels, improving internal processes, and updating and consolidating its business plans. *Id.* at III-37 to III-41.

The Commission, after reviewing the Audit Report, focused on the poor performance of the Company's call centers, in particular the number of abandoned calls and the number of calls answered within thirty seconds.[1] *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket No. 2015-00360, Order – Part II at 44-50 (Dec. 22, 2016) (Part II Order). The Commission stated that the Company had failed, over an extended period, to meet even the lowest of standards with regard to call center performance. *Id.* at 49. This "failure to even come close to meeting such standards over a protracted period" led the Commission to conclude that the Company's service in this regard was "inadequate and unreasonable."[2] *Id.* 49-50. The Commission also found that the Company's credit and collections practices were unreasonable. *Id.* at 50.

b. <u>T&D Operations and Reliability</u>

Liberty conducted an examination into the Company's operation and maintenance of its T&D system, as well as how the Company allocates resources to that system. In addition, Liberty examined how the Company plans, budgets, prioritizes,

[1] An "abandoned call" is one where the caller hangs up before reaching a customer service representative.

[2] Under the provisions of 35-A M.R.S. § 301, a public utility is required to provide safe, reasonable and adequate facilities and service to its customers. To establish whether a utility is complying with Section 301, the Commission employs the so-called "Hogan Standard" which examines whether a company's practice substantially departs from the regular and accepted practice of the company in question as well as that of other utilities in general; whether benefits to a company of the practice are outweighed by the adverse impact of the practice on its ratepayers; and whether a company's practice results in inadequacy of service when considering such factors as the number of customers affected, the duration of the impact, the reason for the company's action and the departure from historic trends. *Part II Order* at 44.

and implements its T&D capital projects, with a focus on reliability improvements.

Overall, Liberty expressed concern with the Company's seeming acceptance of poor reliability performance. *Audit Report* at I-2. Emblematic of this concern, according to Liberty, was the Company's acceptance of internal goals that perpetuate poor performance; performance that is "essentially at the bottom" when compared to the Company's peers. *Id.* at I-2, II-27. While Liberty found that Emera Maine's operating conditions (*e.g.*, climate and geography) do hinder the Company's ability to achieve top-level performance, the Audit Report concluded that the Company could achieve better than "bottom end" performance. *Id.* at I-2.

Liberty also found that the Company failed to adhere to a reasonable inspection regime for roadside and right-of-way inspections in 2014 and 2015 and had conducted no visual inspections of its distribution plant in the Maine Public District (MPD) since at least 2011. *Id.* These failures, according to Liberty, "violate good utility practice for promoting reliability." *Id.*

To help ameliorate the Company's reliability issues, Liberty suggested that the Company prioritize customer outages over cost when planning potential T&D projects. *Id.* at II-29. Liberty also suggested that the Company use more aggressive reliability targets, to put more of the Company's focus on improving reliability. *Id.*

The Commission found that, while the Company appeared to have an acceptable plan to address the missed inspections from 2014 and 2015, its inspection failures were "not a sound management practice." *Part II Order* at 33.

c. <u>CIS</u>

As stated, Emera brought the CIS system on-line in mid-2015, a year-and-a-half after its originally scheduled date and $11 million over its original budget. Liberty's examination of the CIS project and implementation found a management team with inadequate oversight, and a lack of rigor, stability, and experience to implement the project. *Audit Report* at I-5. Liberty concluded that there were several specific factors that led to the Company's failure to implement CIS in a timely and cost-effective manner: no single point of control over the project; a lack of cohesive direction; a lack of experienced staff; a lack of Company resources; excessive change requests; and no detailed implementation plan. *Id.* at IV-21 to IV 24. These shortcomings all led to increased costs and delays.

As a consequence of the delays, Liberty found that the Company "went-live" on CIS before the system was fully functional, necessitating that implementation work continue after the system was operational. *Id.* at I-6. Indeed, CIS was still not fully implemented at the time of the Audit Report, and had no budget for future implementation projects at that time. *Id.* In Liberty's view, the Company should have recognized the need for additional work and associated costs "as early as the vendor bidding process" when its chosen vendor, Cayenta, submitted a bid that estimated the job would take half as long as other bidders, including the second-place bidder who was a "first-tier, very highly experienced provider." *Id.* at IV-25.

As a result, the Company ended up with a system that was not fully functional, over one-third over-budget, eighteen months late, and plagued with system issues.

Liberty concluded its assessment of the Company's CIS implementation with an eleven-item list of challenges CIS must overcome to achieve "a level of performance that [Liberty] would consider strong." *Id.* at I-4.

The Commission, in its Part II Order, endeavored to determine whether the Company acted prudently acted prudently in the acquisition and implementation of CIS. After examining the Audit Report's analysis of the practices of the Company's management, an analysis the Commission found to be credible, and the testimony of the Company's witnesses, the Commission found that the Company's management did not act in a prudent manner with regard to CIS implementation. *Part II Order* at 63-69.

Having found that the Company acted imprudently with regard to the implementation of CIS, the Commission then determined the impact of such imprudence. The Commission recognized that while this was, necessarily, an imprecise analysis, the Commission found that imprecision does not excuse the imprudent conduct. *Id.* at 70. Ultimately, the Commission relied on Liberty's analysis of the harm caused by the Company's imprudent conduct, and ordered a disallowance of nearly $2.5 million of the Company's CIS investment.

B. <u>Overview Company Position</u>

On October 2, 2017, the Company submitted its direct testimony in support of its request to raise distribution rates by approximately 12% or by $10 million. The Company breaks down the overall increase as follows:

Table 1[3]

Description	Amount
Investment in capital and associated costs	$3.9
Reliability (Vegetation Mgt, Danger Trees, Storm Response & Engineering Resources)	2.0
Customer Experience / Service Levels	1.2
Return to Appropriate ROE (9.5%)	1.1
Roll off of amortizations of Retiree Medical Prior Service Cost Gains	1.9
Other	0.7
	10.8
Increased revenues from higher sales vs 2016 rate case	(0.8)
Total[4]	$10.0

In support of its rate increase request, Emera states that:

1. The increase is necessary for Emera Maine to provide safe, reasonable and adequate facilities and service. This will include specifically addressing the areas where the Company's facilities or service was found to be deficient by the MPUC in its 2016 distribution rate proceeding Order.
2. The Company is operating as efficiently as possible and is utilizing sound management practices.
3. The increase is required by the Company in order to attract necessary capital on just and reasonable terms.

The Company further notes that the capital and operating investments will, over time, result in fewer outages and less hours without power in normal and severe weather conditions; that the increased resources of the "Customer Experience Functions" will ensure that regular service levels are consistently meeting the expectations of the Company's customers and regulators today and into the future; and,

[3] Source Richardson Prof. Dir Test at PP-6

finally, that Emera has responded appropriately and successfully to the Commission's concerns set forth in Docket 2015-00360 which were the basis for the Commission's 50 basis point ROE reduction. Therefore, the Company argues that the 50-basis point reduction should be removed at this time.

In support of its position that its rates are, and will continue to be, just and reasonable, the Company states that even with the proposed increase in this filing, real distribution rates will be approximately at the same level they were fifteen years ago. In terms of overall delivery price (transmission, distribution, stranded cost and conservation), real prices are less than they were fifteen years ago, and assuming today's supply costs, overall electricity bills will also be lower than they were fifteen years ago.

In response to the Commission's invitation that it consider presenting a rate plan that could provide incentives for improved performance and enhanced earnings, along with its rate increase proposal in this case, the Company declined, stating that it needed to advance its thinking in several areas before it was willing to propose a multi-year plan. The Company noted that it will continue to advance its thinking in these areas, and may choose to file such a proposal in a future case.

C. Overview Staff Position

The Company's filing for a 12.0% rate increase in this case follows a request for a $6.5 million, or 8.0%, increase filed in March 2016 (Docket No. 2015-00360) and an approximate $7.0 million increase or 9.4% filed in December 2013 (Docket No. 2013-

00443). With regard to the Company's claims that its rates will continue to be reasonable even after its proposed increase, the Staff has compared residential bills for Emera Maine customers to a regional average. The bill amounts include only charges for distribution service so that the comparison is internally consistent, and compares costs that are within management control. For example, charges for energy efficiency and other policy-related programs have been excluded. The regional average includes the other investor owned T&D utilities in New England, except United Illuminating, whose distribution rates appear to be anomalous. Staff has also compared Emera Maine's residential distribution service charges to Central Maine Power's (CMP). At current rate levels, the charges for Emera Maine residential customers are within +/- 10% of the regional average, depending on monthly kWh usage. However, with the proposed 12% increase, the charges for Emera Maine residential customers would be above the regional average. For example, for a residential customer using 550 kWh/month, charges for EM-BHD residential customers would be about 9% above the regional average, and at higher monthly usage levels, the differential would increase. At a monthly usage of 1,250 kWh, charges for EM-BHD customers would be above the regional average by almost 19%. Compared to CMP, the charges to Emera Maine residential customers at existing rates range from about 19% to almost 50% higher, depending on kWh usage, and with the proposed 12% increase, the differential range would increase to 33% to 65%.

In its direct case, Company witness Holyoke points to the fact that the Company's customer service rankings in J.D. Power's Electric Utility Residential Customer Satisfaction Survey-Comparison of Emera vs East Midsize [**REDACTED]**

As discussed in this Bench Analysis, the Staff recognizes that in several areas the Company has made strides toward meeting the performance standards set forth in its Commission's Order in Docket No. 2015-00360. In other cases, however, the Company's management practices continue to be inefficient and below reasonable expectations, and in Staff's view warrant setting the allowed Return on Equity (ROE) in this case towards the lower end of the range of allowed reasonable returns. The Staff also believes that the Company's rate levels, recent rate increases, and management efficiency should be factored in what projects and what level of capital spending should be approved here.

As discussed above, the Company did not file a rate plan proposal as part of its rate increase request in this proceeding. Given the compressed schedule in this case and scope of this case, the Staff is not proposing a rate plan as part of this Bench Analysis. The Staff recommends, however, that at the conclusion of this case, the Commission initiate a follow-up proceeding to establish a rate plan for Emera Maine to take effect on July 1, 2019.

II. RELIABILITY

A. Overall Reliability Levels

One of the key conclusions of the Liberty Report was that Emera Maine's reliability statistics were relatively poor and that the Company was apparently willing to accept these historical low levels of performance. The following table illustrates Emera's historic System Average Interruption Frequency Index (SAIFI) and Customer Average

Interruption Duration Index (CAIDI) performance from which Liberty based their conclusions:

Table 2[5]

Regional & System-Wide SAIFI									
Year	Pre Exclusion			Post Exclusion 10% Impact Method			Post Exclusion IEEE 2.5 Beta Method		
	BHD	MPD	EM	BHD	MPD	EM	BHD	MPD	EM
2012	2.68	2.56	2.65	1.64	2.26	1.78	2.19	2.49	2.26
2013	4.91	3.30	4.54	2.29	2.42	2.32	2.78	2.91	2.81
2014	4.54	3.11	4.21	1.98	2.38	2.08	2.93	2.71	2.88
2015	2.78	1.89	2.58	1.67	1.56	1.65	2.48	1.86	2.34

Table 3[6]

Regional & System-Wide CAIDI

[5] EXM 04-05
[6] Id.

Year	Pre Exclusion			Post Exclusion 10% Impact Method			Post Exclusion IEEE 2.5 Beta Method		
	BHD	MPD	EM	BHD	MPD	EM	BHD	MPD	EM
2012	2.45	1.37	2.21	1.84	1.40	1.72	2.02	1.36	1.85
2013	8.41	1.38	7.23	2.24	1.40	2.05	2.41	1.34	2.15
2014	10.06	2.53	8.77	2.36	1.75	2.21	2.27	1.77	2.16
2015	2.27	2.26	2.27	2.04	2.26	2.09	1.93	2.28	1.99

Emera calculates SAIFI and CAIDI with excludable events using both the IEEE 2.5 Beta Method as well as 10% of customers over a 24-hour period. For internal use, Emera prefers the 10% of customers metric as they believe it better reflects major weather events. As can be seen in the tables above and below, this approach typically produces more favorable results as it excludes more weather-related events than the IEEE Beta Method. For example, in 2016 the Company excluded 26 event days using the 10% approach compared to five using the IEEE Beta Method. EXM-004-006, 004-007. Additionally, Emera removes from the SAIFI calculation events where cars making contact with utility poles cause customer outages. Emera argues they only include events over which they have control in the calculation of SAIFI; however, this approach masks the true reliability performance experienced by the customer. CMP's most recently approved ARP Service Quality Index Performance Metric incorporates the IEEE Beta Method in response to the Staff's concerns that the 10% Impact Method did not provide the utility with the correct incentives and could be manipulated. In addition, the IEEE Beta Method has become the standard method for excluding storm events in calculating SAIFI and CAIDI performance and thus provides a means of comparing utility performance on an apples-to-apples basis. Staff recommends that the

Commission require the Company report its reliability metrics using the IEEE Beta Method which we believe is consistent with Emera's desire to participate in future benchmarking efforts that use more scientific rigor and provide normalized results. EXM-004-012.

As part of its Rebuttal in the 2015-00360 case, the Company stated that it has accepted Liberty's recommendation that it should strive for reliability improvement and has adopted a five-year improvement approach. In its effort to improve reliability performance, the Company has adopted several of the recommendations from the Liberty Report. First, Emera adopted "improvement range" targets for SAIFI and CAIDI which would target a 2.5% reduction per year from the previous year's five-year average. This reduction is projected to continue through 2019 beyond which the Company will re-evaluate its approach.

The second process improvement involves implementing a new process of ranking reliability projects using the "avoided customer interruption method" which assigns a cost per avoided customer interruption ($/ ACI) allowing the Company to compare reliability projects in a quantitative way. This approach will require a more rigorous approach to capital planning and should over time positively affect system reliability. However, too strict of focus on spending where it can impact the largest number of customers can also lead to a two–tiered system where customers in higher density areas receive more reliable service than those in more rural areas. Using the $/ ACI metric in conjunction with customer or feeder level reliability metrics could mitigate this danger.

The following tables represent Emera's reliability performance since the Liberty Report was published.

Table 4

Regional & System-Wide SAIFI									
Year	**Pre Exclusion**			**Post Exclusion 10% Impact Method**			**Post Exclusion IEEE 2.5 Beta Method**		
	BHD	**MPD**	**EM**	**BHD**	**MPD**	**EM**	**BHD**	**MPD**	**EM**
2016	**4.61**	**3.12**	**4.28**	**2.27**	**1.88**	**2.19**	**3.57**	**3.06**	**3.46**
2017 YTD	**1.72**	**1.18**	**1.60**	**1.34**	**1.10**	**1.29**	**1.60**	**1.18**	**1.51**

Table 5

Regional & System-Wide CAIDI									
Year	**Pre Exclusion**			**Post Exclusion 10% Impact Method**			**Post Exclusion IEEE 2.5 Beta Method**		
	BHD	**MPD**	**EM**	**BHD**	**MPD**	**EM**	**BHD**	**MPD**	**EM**
2016	**4.37**	**1.99**	**3.99**	**2.28**	**1.45**	**2.13**	**2.50**	**1.87**	**2.37**
2017 YTD	**3.27**	**1.79**	**3.03**	**2.56**	**1.79**	**2.43**	**2.56**	**1.79**	**2.43**

As evidenced by the results, the Company performed poorly in 2016. SAIFI was significantly higher than any of the preceding years and CAIDI was also slightly higher. 2017 SAIFI metrics have shown modest improvement year-to-date from historical performance. However, CAIDI performance has continued to degrade. SAIFI is currently forecast to be slightly under 2.00 while CAIDI is expected to finish the year at approximately 2.4 using the Company's preferred 10% of customers out metric. ODR-001-010. This performance would place the SAIFI metric in the upper range of the new "improvement range objectives" for SAIFI and above the range for CAIDI. Belliveau Pref. Dir. Test. RB-7. It is Staff's view, that while Emera has taken positive steps to remedy its reliability issues, at this point, it is too early to determine whether the proposed improvements have completely remedied such issues. Ongoing demonstrated results and adherence to the proposed programs will be needed to properly judge the effectiveness of Emera's redesigned reliability program.

Emera has also proposed to make changes to its vegetation management and inspection processes to improve reliability. These programs are discussed below.

B. Inspections

As was identified in the Liberty Report, Emera "failed to complete ROW Foot Patrol, Drive-by Roadside & Special Roadside, Critical Crossings and Lattice Tower visual inspections in 2014 and 2015. *Liberty Report* at II-15. In its testimony, Emera asserts it is meeting its plan to make-up the missed inspections over the 2016-2019 period[7]. Emera notes that it achieved the goal in 2016 and that it is on target to complete 2017's target as well. The following table illustrates Emera's plan to complete the necessary incremental inspection miles each year.

[7] To address this concern, in 2016, Emera hired contractors to help complete its outstanding inspections from 2014 and 2015 and created a plan to catch-up to the inspection cycle by the end of 2019. Emera's transmission overhead inspection program was fully caught up as of the first quarter of 2017. Emera's distribution overhead inspection plan will be completely caught up by the end of 2019. Belliveau Pref. Dir. Test. RB 31.

Distribution Overhead Inspection Program Catch Up Plan[8]

Table 6

Emera Maine Distribution Overhead Inspection Program	Total Primary Distribution Miles	Average Annual Goal Miles for 6 year cycle	2016 Goal	2017 Goal	2018 Goal	2019 Goal	2020 Goal (Avg Cycle)
Visual inspection Miles (Cycle-based)	6080	1013	1486	1354	1371	1395	1013

Not unexpectedly, there is a cost associated with the catch-up work. The following table provides the estimated incremental cost of the make-up inspection work.

Table 7[9]

Distribution Line Inspections - Catch Up Work	2016	2017	2018	2019
Total Miles for Program (including catch up)	1,486	1,340	1,329	1,334
Total Costs for Program (including catch up)	$221,426	$94,784	$93,924	$190,628
Approximate Miles for Balanced 6 yr Cycle Program	1,013	1,013	1,013	1,013
Catch up Miles (1 - 3)	473	327	316	321
Catch up Miles as a % of Total Miles (4/1)	32%	24%	24%	24%
Costs for Catch Up Miles (2 * 5)	$70,480	$22,748	$22,542	$45,751

While we certainly encourage Emera to continue to meet its targets to get back on track, it is Staff's position that Emera should not be allowed to recover this incremental cost. The costs for the distribution line inspections not performed by the Company were included in the rates at the time the decision was made to discontinue the inspection program.

---

[8] Belliveau Pref. Dir. Test. RB-35.

[9] EXM-004-033, Attachment A

It then follows that providing recovery of this incremental amount would be double counting. In addition to the line inspection programs, Emera has proposed additional inspection programs with the intention to improve reliability. These new programs include an Infrared Scanning program for line sections that serve more than 500 customers; ultrasound testing based on line voltage; and an expanded ground line assessment program. The following table illustrates Emera's inspection programs and cycles.

Table 8[10]

Emera Maine Core Transmission Line Inspection and Treatment Program			
Inspection Technique	Freq	Inspector	Comment
ROW Foot Patrol	5 Year Cycle	Contractor & In-house	
Drive-by Roadside Patrol	6 Year Cycle	Contractor & In-house	Offset with Roadside S&B, effective assessment period 3 year cycle
Critical Crossing Inspections	3 Year Cycle	Contractor & In-house	
Routine ROW Aerial Patrol	Minimum 1 Patrol Annually	In-house	Typically 2 conducted, 1 winter with leaves off & 1 summer leaves on
Thermal ROW Inspection	Annually	Contractor	Prior to 2015 only 100+ kV inspected, expanded to all voltage classes in 2015
Thermal Roadside Inspection	Annually	Contractor	Added to Core Plan in 2015
ROW Ground Line Wood Pole Inspection & Treatment	10 Year Inspect Cycle/5 Year Cycle Retreat	Contractor	
Roadside Wood Pole Sound & Bore	6 Year Cycle	Contractor	Added to Core Plan in 2014
Steel Lattice Tower Inspection	5 Year Cycle	In-house	

Emera's decision to move the ground line pole testing inspection program from a pilot to an ongoing cycle inspection program is expected to cost approximately $160,000 per year. Additionally, the infrared and ultrasonic inspection programs will cost approximately $64,750 annually. Each of these new programs is designed to improve Emera's awareness of its infrastructure condition. The Staff does not object to the adoption of these new programs.

The following table presents the open inspection issues at the close of each year.

---

[10] Belliveau Pref. Dir. Test – Exhibit RB3

Table 9[11]

Distribution Issues Open at End of Year	
Year	**Qty**
2012	1,355
2013	1,571
2014	1,659
2015	1,925
2016	4,606
2017	23,282

As Emera explained at the 12/1/17 Technical Conference, some of the uptick in 2016 and 2017 was a result in making up inspection work that was not performed in 2014 and 2015. That trend will continue until 2019 when the make-up inspections are completed. Tr. 26 (Dec. 1, 2017). Additionally, Emera sees several of these new programs creating a one-time increase to the backlog that will be addressed by a measured approach during a routine cycle.

Currently Emera places issues identified in the inspection process in one of two buckets; issues which require immediate attention to address a reliability or safety issue, or other issues which will be addressed when other work on the line will be done. Given the number of open issues carried forward, Staff recommends that the Company develop a more robust classification system so identified problems which may become reliability or safety issues before the next inspection cycle are separately classified and calendared for work.

C. <u>Vegetation Management</u>

---

[11] ODR-001-023, Attachment C

In its filing, Emera proposes to increase the frequency of its vegetation cycle trim program from the current six-year cycle to a five-year cycle[12]. Under this proposed change, Emera would be trimming 200 more circuit miles per year than under the current six- year plan. Emera estimates the average annual incremental spend would be approximately $754,000. OPA-001-012. Table 10 illustrates the historic vegetation cycle trim spending for the past five years.

Table 10[13]

District		2012	2013	2014	2015	2016	2012 - 2016 5 yr Average	2014 - 2016 3 yr Average	2017 YTD Through Sep
BHD	Costs	$ 2,344,405	$ 2,471,405	$ 3,069,124	$ 3,273,783	$ 3,136,843	$ 2,859,112	$ 3,159,917	$ 2,795,149
MPD	Costs	$ 846,309	$ 927,589	$ 1,100,728	$ 1,212,698	$ 768,582	$ 971,181	$ 1,027,336	$ 282,921
BHD + MPD Total	Costs	$ 3,190,714	$ 3,398,994	$ 4,169,852	$ 4,486,481	$ 3,905,425	$ 3,830,293	$ 4,187,253	$ 3,078,070
BHD	Miles	665	677	848	768	689	729	768	635
MPD	Miles	256	309	539	590	213	381	447	105
BHD + MPD	Miles	921	985	1387	1358	902	1111	1216	740

Currently, tree-related outages account for 177,490 customer interruptions per year, or approximately 56% of the Company's total annual customer interruptions. EXM-004-015. As Emera notes in its testimony, moving to a five-year cycle would be consistent with the vegetation management cycle currently administered by CMP. Staff agrees that there are reliability benefits that can be achieved with more frequent tree trimming.

---

[12] Beginning in 2014 Emera began its six-year cycle trim program.

[13] EXM-004-019, Attachment A

The Company plans to keep its current standard for its primary distribution vegetation trim clearances of 10 feet to the side of any wire and 15 feet above any wire, with all vegetation below the wires to the edge of the tree line being cut, allowing for certain exceptions. As Emera notes, the “clearances were specified to maintain adequate distance for vegetation based upon regional growth rates in alignment with utility practice in Maine and other New England states.” ODR-001-029. Staff supports maintaining existing clearance practices.

Emera is also seeking additional funding to increase the number of trees it targets annually under its “Danger Tree” program. Emera currently performs danger tree removal on approximately 110 miles per year of its 6,100 miles of primary distribution circuits (less than 2%). EXM-004-015. Over the past five years, Emera performance in the Danger Tree area is as follows:

Table 11[14]

Distri		201	201	2014	2015	2016	2014 -	2017

[14] EXM-04-020 Attachment A

BHD	Cost			$ 115,88	$ 52,11	$ 39,85	$	$
MPD	Cost			$ 86,52	$ 43,09	$ 28,93	$ 52,85	$ 17,84
BHD +	Cost	**See**		$ 202,41	$ 95,21	$ 68,78	$ 122,13	$ 152,34
BHD	Mile	40	62	160	67	65	97	120
MPD	Mile	0	7	92	43	22	52	35
BHD +	Mile	40	69	252	110	86	149	155

Note 1 - Cost data for Danger Tree vs Cycle Trim was not segregated in our Financial Information System during these years.

The enhanced program would increase the number of circuit miles for Danger Tree removal by 566 miles annually. Belliveau Pref. Dir. Test. RB-28. Emera states that the annual cost of this enhanced program will be $458,000 and will avoid 4,443 tree caused outages, for an estimated 10,464 hours, annually. ODR 001-030. As illustrated above, this would be a significant increase to the Danger Tree budget compared to historic spending levels. The 2014 totals included in the table reflect a mid- year decision by the Company to address poor reliability by targeting an additional 140 circuit miles. ODR-001-025. Even with the increased focus in 2014, the 2014 spending level is half of what the Company is projecting going forward. With the reservations noted below, the Staff is generally supportive of the Company's proposed vegetation management program changes.

First, the current agreement with Emera's vegetation plan contractor expires 7/31/2018, at which time a new contract will be in force for the enhanced program. EXM-004-018. Staff has concerns that the proposed incremental costs are not fully developed as the Company has not yet issued an RFP nor has it received pricing from vendors for the new vegetation management program, including its enhanced Danger Tree program. EXM-004-015. Emera has estimated that the total annual cost for the five-year cycle with the enhanced Danger Tree contract is expected to be in the range of $5.5 million. OPA 001-005. We note, the cost of CMP's latest vegetation cycle trim procurement effort decreased from $25 million to $16 million per year as a result of having already gone through the cycle. CMP used a portion of these savings to fund the enhanced Danger Tree and other vegetation management programs. *Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014")*, Docket No. 2013-00168, Bench Analysis at 78 (Dec. 12, 2013). Emera will complete its current six-year cycle in 2020. It is feasible the new contract will show similar pricing trends as experienced by CMP.

Second, the Staff is somewhat concerned how the identification of Danger Trees will be carried out. The Staff recommends the identification of these Danger Trees not be left solely to the direction of the contractor alone but rather be done in coordination with the utility arborist.

Finally, and most importantly, vegetation management programs have historically been curtailed by utilities when budgets are stressed. While Staff is supportive of increased funding for improving vegetation management practices, the utility must commit to completing the projected trimming per its proposed program. The Staff recommends that, as is the case with CMP, Emera be required to report on the status of its vegetation management program on an annual basis.

E. Staff Assessment

A well targeted and efficient capital plan focusing on reliability improvements is compatible with the enhanced inspection and vegetation management efforts. Emera appears to be aligning the capital expenditures to coincide with the cycle work that it is doing and using the inspection data to make informed decisions. As noted with other aspects of the reliability improvement effort, Emera is making positive efforts towards improving system reliability but at this time we cannot state with certainty how effective these initiatives are until the results can be demonstrated over time. Therefore, Staff recommends that Emera shall be required to file Annual Reliability Reports with the Commission each year by April 1 which provide the following service quality and reliability performance information for the prior year:

a. Customer Average Interruption Duration Index (CAIDI); System Average Interruption Frequency Index (SAIFI); Feeder Average Interruption Frequency Index (FAIFI) (for circuits that exceed 6.3); Business Calls Answered within 30 seconds; and New Service Installations. This information shall be reported with and without excludable days. For the purposes of determining excludable days, Emera shall use the IEEE 2.5 Beta method on calendar day basis.

b. Outage by Cause Code by Service Center; summary of the results under Emera's vegetation management (cycle trim and enhanced trimming) and line inspection programs; age of distribution plant by major plant category.

III. CUSTOMER SERVICE

A. Docket No. 2015-00360, Findings and Overview

In Docket No. 2015-00360, the Commission focused its discussion on those areas where the Liberty Auditors found problems with Emera's customer service that were relevant to its setting of rates and where the Company disagreed with Liberty's findings and/or recommendations. These areas related to customer service organization and staffing, contact center performance, customer satisfaction measurement, payment and collections/bad debt, and billing.

Under the provisions of 35-A M.R.S. § 301, a public utility is required to provide safe, reasonable and adequate facilities and service to its customers. Because the statutory standard of reasonable and adequate service cannot be defined with precision, the Commission has the responsibility to consider the facts and circumstances of a particular case to determine whether the service provided is reasonable and adequate. *Hogan v Hampden Telephone Company* F.C. 2438, 36 PUR 4th 480, 485 (May 16, 1988).

The Commission has employed the following three criteria in determining whether service practices were unreasonable or inadequate:

1) whether the company's practice substantially departs from the regular and accepted practice of the company in question as well as that of other utilities in general;
2) whether benefits to the company of the practice are outweighed by the adverse impact of the practice on its ratepayers; and
3) whether the company's practice results in inadequacy of service when considering such factors as the number of customers affected, the duration of the impact, the reason for the company's action and the departure from historic trends.

Hogan v Hampden, supra. 36 PUR 4th at 485.

Evidence warranting a finding adverse to the utility on any one or more of these criteria is sufficient to support a finding that the practice is unreasonable. For the reasons discussed below, Staff concludes that from 2014 to the present, Emera Maine's call center performance has failed to meet criteria (1) and (3) above and, therefore, must be considered inadequate and unreasonable.

As part of BHE's earlier Alternative Rate Plan (ARP), the Commission included a Call Answering Metric as part of the Service Quality Index (SQI) penalty mechanism. *Bangor Hydro Electric Company, Request for Approval of Alternative Rate Plan,* Docket No. 2001-00410 Order Approving Stipulation (June 11, 2002). The Call Answering Metric established in BHE's ARP was 80% of calls answered in 30 seconds. The 80/30 Call Answering criteria is essentially the same standard that has been employed in all of Central Maine Power Company's ARPs.[15] After the expiration of BHE's ARP, the Company retained the 80/30 standard as its performance target up until January 2015. The Liberty Auditors found that the 80/30 Call Answer Metric is a common target in the utility industry.[16]

Until 2012, BHE consistently met the 80/30 target on an annual basis. Beginning in mid-2013, BHD started missing the 80/30 monthly target on a fairly consistent basis.

---

[15] See, *Central Maine Power Company, Chapter 120 Information (Post ARP 2000) Transmission and Distribution Utility Revenue Requirements and Rate Design and Request for Alternative Rate Plan,* Docket No. 2007-00215, Order Approving Stipulation (July 1, 2008).

[16] August 15, 2016 Tech. Conf. in Docket No. 2015-00360, Tr. 56.

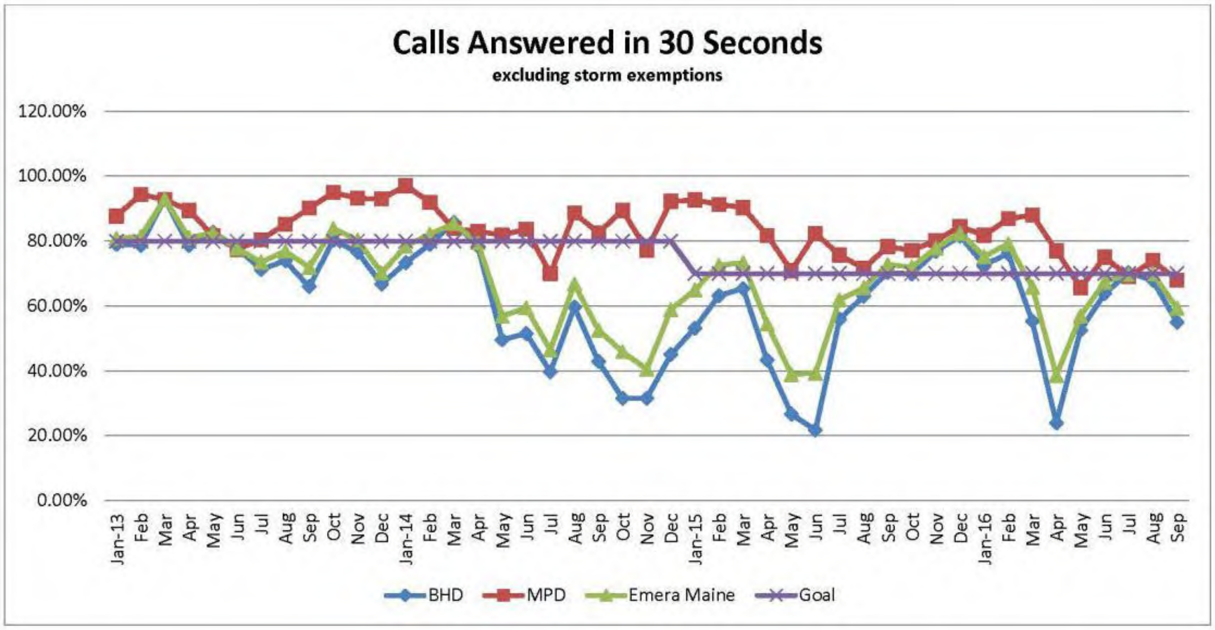
Call answering performance at the BHD continued to decline in 2014 and went as low as 30% in October and November 2014. In 2014, on a company-wide annual basis, call answering performance was 64% of call answered in 30 seconds.

In January 2015, Emera Maine lowered its call answering target to 70% of calls answered in 30 seconds. Ms. Holyoke explained that the Company took this action since it was obvious to management that it would not be able to meet the 80/30 target in 2015 and that it wanted to provide incentives to its employees to keep morale up.[17] The Company also explained that management did not want to provide incentives to its employees to inappropriately shorten calls during CIS deployment. On an annual company-wide basis, the Company's call answering metric performance was 66% in 2015, with the poorest performance months being May and June (the months of CIS go-live). During those months, the performance at the BHD call-center was slightly above 20% and on a company-wide basis performance was 40%.

Since go-live, performance steadily improved through December 2015 and exceeded the Company's revised 70/30 target in consecutive months. After February 2016, performance faltered some and in April 2016 performance at the BHD was again at about 22%. The Company's Calls Answered in 30 Seconds (excluding storms) since January 2013 is presented in Figure 1 below.

Figure 1

[17] Sept. 28, 2016 Tech. Conf. in Docket No. 2015-00360, Tr. 37.



Another important indicator of call center performance is the Calls Abandoned statistic which is a measure of the instances in which callers are giving up and abandoning their calls. Liberty stated that good utility practice limits abandonment rates to 5 to 10 percent of calls received. Liberty found that Emera Maine has not achieved this standard since 2013 noting that over the past three years, Emera Maine's CSRs have put callers on hold more and more frequently. Emera Maine disagrees with Liberty's assessments and argues that other than four exceptional peaks resulting from unusually powerful storms (in December 2013, July 2014 and November 2014) and the launch of the CIS, (June 2015) performance has consistently been below 10%. The Commission concluded that the data presented supports the conclusion that Emera Maine's call abandonment rates since the start of 2013 have frequently been above 10% and have consistently been above the 5% level. The Commission further concluded that given the assessments provided to the Company about the complexity and difficulties encountered in CIS projects, the need for additional resources at the call center could have, and should have, been known to the Company.

In its Docket No. 2015-00360 Order, the Commission found that the Company's Call Center practices substantially depart from the regular and accepted practice of both the Company and of other utilities and that the Company's Call Center practices result in inadequacy of service when considering the number of customers affected, the duration of the impact, the departure from historic trends and the Company's failure to adequately take sufficient steps to plan for the impact of the CIS implementation on Call Center resources.

In addition to call center performance, another area in customer service where the Commission found Emera Maine's performance to be below a standard that it would consider to be reasonable was in the credit and collections or "meter to cash" function. The Commission stated that the BHD credit group has not consistently worked the write-off process over the past five years and in each year a portion of the write-offs should have been written in the prior year. This inconsistency created an unrepresentative view of write-off activity making it difficult to assess how the Company is doing in any one year or what the likely amount of bad debt will be in the future. The Commission also found that the Company's meter to cash function has been hampered by the Company trying to have CSRs multi-task and do both credit and collections work and take customer calls. It is likely that this problem has lengthened collection times and ultimately caused increases in bad debt expense.

These and other findings in Docket No. 2015-00360 formed the basis of a Commission ordered reduction in the Company's allowed ROE to the low end of the range established in that case. The Commission noted that the adjustment to the Company's ROE shall remain in effect until the Company demonstrates to the Commission that its management practices and efficiencies, particularly in the areas of customer service and with respect to the Company's systems maintenance practices, have improved and have provided real benefits to ratepayers. The Commission further stated in its decision:

> [t]hus, the Company is not forestalled from returning with a rate case in which they demonstrate that the numerous improvements that management referred to during the course of this case have borne fruit and that the trends in service are in the right direction. Additionally, the Company might consider presenting a multi-year alternative rate plan that could both provide incentive for improved performance and enhanced earnings.

The Company states that the purpose of its Customer Experience testimony is to detail improvements in customer service at Emera since the last rate case and address shortcomings identified by the Commission in that case as a basis for the implementation of a "Management Efficiency Adjustment" to the Company's ROE. Holyoke Pref. Dir. Test. 3. The Company goes on to explain the improvements it has made to its customer service functions. It further states that on a daily basis, it is exceeding the annual target of 80% of calls answered within 30 seconds in the contact center, has improved its processes to identify bill errors before they happen, and has improved its credit and collections processes. In short, the Company states, it has addressed the shortcomings that the Commission identified a little less than a year ago in the rate case and thus the Commission should eliminate the Management Efficiency Adjustment. Holyoke Pref. Dir. Test. 45. Each of these areas is discussed in detail below.

B. Overall Customer Experience Improvements

The Company states that its high-level Customer Experience strategy is in effect and continues to evolve. The Company goes on to state that originally, its goal was to deliver a "formal five-year strategy and plan" in 2016. However, its "current approach to the strategy is an ongoing, iterative process." The Company's strategic focus is to prioritize projects with the greatest value to customers and the completion of a formal five-year plan is on hold until certain technology plans are formulated regarding the customer information system in the MPD. The Company states that it must first "understand future direction of this foundational customer information system before determining the best way to meet customer needs through technology investments… that a solid understanding of the company's plans for the future of the CIS is necessary to ensure that customer technology improvements are undertaken at least cost and in the right sequence." Holyoke Pref. Dir. Test. 10-11.

The lack of an over-arching, high level Customer Experience Strategic Plan is of concern to Commission Staff. In response to the Management Audit Findings regarding customer service problems at Emera, the Company stated that Emera Maine was in the process of creating a Five-Year Customer Experience Strategy and Plan. The Company stated that it intended to work with stakeholders, including the Commission and the Public Advocate, to explore their thoughts and views about additional costs to customers as a result of implementing some enhancements. *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket No. 2015-00360, Holyoke Rebuttal Test. 3. These discussions have not happened and the Five-Year Plan has not been completed, yet the Company is requesting approval in this case to implement customer service enhancements, some costing significant amounts of money.

In its testimony, the Company states that because it still has decisions to make regarding foundational technology systems, such as customer information systems and geographic information systems, the appropriate steps to be taken to provide technology tools to customers is dependent on those decisions. Some shorter-term decisions have been made in the interim, but longer term planning awaits these decisions which are actively under consideration and should be made in the next six months. Holyoke Pref. Dir. Test. 11. It is not clear from this statement whether technology decisions or the Five-Year Customer Experience Plan are driving long-term planning decisions.

This seems to contradict the position that Company took in the previous rate case.[18] In that case, the Company indicated that the Five-Year Customer Experience Strategy was the over-arching, long-term planning tool for the Company. In a technical conference held on September 28, 2016 in Docket No. 2015-00360, Commission Staff asked Emera about the time frame for having a draft of the five-year plan and the Company responded:

> [S]ix to eight months is probably fair. I -- I -- we want to make sure we are fully engaging stakeholders. So you know, I think a six-month timeframe is -- is reasonable. But we're not looking at -- what we want to do with this strategy and plan is not have like a five-page PowerPoint of -- we want to be able to be costing things quite -- provide a good amount of detail, more of a whitepaper approach than a PowerPoint kind of

[18] Docket 2015-00360.

presentation.

Emera Maine, Request for Approval of a Proposed Rate Increase, Docket No. 2015-00360, Tr. 54 (Sept. 28, 2016).

Further, in that same technical conference, Commission Staff asked the Company what steps the Company needed to take to get the five-year plan in place and the Company responded:

> [W]e have to -- you know, once we get it in a more final form, would present it to our board and ensure that our board of directors believes that it meets the needs of the business going forward and that -- that our plans are -- are something that we can commit to financially. And -- and then we would move to -- to implementing, but I'm still moving with -- even with an absent of the total plan and vision, we still have projects that we're going to be implementing that will fall within that plan going forward but don't maybe -- so some of the process improvement work we're already going to be commencing planning on that even before we get approval for the -- for the overall vision and strategy. And that's what I've done. My approach has been really over the course of the past year is where I've seen opportunity to make improvements, I'll -- if I can make them quickly, we'll make them. *But if they require bigger investment or some decisions about sequencing, particularly where there's major investment, that's something that needs to wait until we have a bigger picture in focus*. (emphasis added)

Id. at 55.

Though the Company stated in the previous rate case that it would produce a Five-Year Customer Experience Strategy and Plan in collaboration with stakeholders including the Commission and OPA, and that it would obtain Board approval for the Company's "vision and strategy" for improving customer service, the Company has proposed significant customer service projects that involve significant amounts of money with no Five-Year Customer Experience Plan and no long-term planning.

C. Call Center Performance

In response to concerns raised in the Liberty Report, and in conjunction with its ongoing Customer Service Center relocation, Emera Maine states it has re-organized the management and staffing of its call centers and addressed its hiring and training practices. The Company also states that it has engaged an independent consultant to help assess training and support for the call center staff and another consultant to look at how the Interactive Voice Recorder (IVR) can be improved to help customers get quicker answers to their questions. Holyoke Pref. Dir Test. 18.

The Company states that it added two new assistant manager positions, increased the number of supervisors and has hired additional customer service representatives. In the Company's "Customer Experience" testimony, Table KH-2 shows that total Customer Contact Center CSRs/Lead CSRs and Trainers has increased from a low of 41 in 2016 to the current high of 58. This number does not include additional supervisors, managers and other staff. The Company claims that as a direct result of their staffing and procedural changes, they have made the improvements in JD Power rankings noted earlier. Holyoke Pref. Dir Test. 14.

The Company further states that due to the changes discussed above, the Contact Center has been consistently performing at service levels that exceed 80% of calls answered in 30 seconds or less, measured daily since May of this year and is tracking to meet its annual target of 80/30 for the foreseeable future. *Id*. at 15-16. Further, the Company states that recently, its call abandonment rate has been approximately 2%-4%

Staff agrees with the Company that its call answer performance has improved and is tracking in the correct direction. Staff is unsure, however, that the Company will meet the target of 80/30 on an annual basis for 2017. A review of Table 12 below shows that through October 2017, the Company has answered 75% of calls within 30 seconds with a 4% abandonment rate.

Table 12

Year	Average Speed to Answer	% Calls Answered in 30 seconds	% Calls Abandoned
2012**	53	74%	8%
2013	28	82%	4%
2014	73	66%	9%
2015	110	66%	11%
2016	82	64%	7%
2017 (YTD)***	43	75%	4%

* 2012 does not include MPD
** 2012 annual only Oct-Dec
***2017 through Oct.

EXM-002-012, Attachment A

Further, the Company itself forecasts in its Customer Experience Index that it will answer between 74% and 78% of calls within 30 seconds in 2017. This result is slightly lower than the 80% target. While Staff agrees that Company's call answer performance has improved and is heading in the right direction, it will need to meet it calls answer and call abandonment targets on an annual basis to demonstrate that its call answer performance represents “reasonable and adequate service.”

D. Credit and Collections

1. Write Offs

In Docket No. 2015-00360, the Commission found that BHD had not consistently worked the write-off process over the past five years and in each year a portion of the write-offs should have been written in the prior year. The Commission also found that that the Company’s meter to cash function has been hampered by the Company trying to have CSRs multi-task and do both credit and collections work and take customer calls and that this problem has lengthened collection times and ultimately caused increases in bad debt expense. *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket No. 2015-00360, Order (Part II) at 50 (Dec. 22, 2016).

In its testimony, the Company states that it has automated its bad debt write off process and established a manual exceptions process which has allowed write offs to occur in a timely fashion and during the time-period (year) when they should. Holyoke Pref. Dir Test. 28. These actions appear to have addressed the Commission’s concern that write offs occur during the appropriate year.

2. Billing and Payment Group

The Commission found in Docket No. 2015-00360 that the Company’s meter to cash function was hampered by the Company trying to have CSRs multi-task and do both credit and collections work and take customer calls. In that case, the Company stated that it planned to reduce multitasking in the Contact Center by moving functions more closely related to billing and payment, such as billing adjustments and development of disconnection logs, out of the Contact Center and into the new Billing and Payment group. The Company has stated in this case that it implemented a new structure that refined the focus of the customer contact center by separating credit and collections and billing responsibility and shifting responsibility for those functions into a new group, Billing and Payment, that was formed to focus on the "meter to cash" process. Holyoke Pref. Dir Test. 4. Despite these claims, the Company acknowledges that the functions discussed above have not yet been moved from the Contact Center to the new Billing and Payment group.

In a technical conference held on November 30, 2017, Commission Staff asked the Company about the delay in moving the credit and collection functions from the Contact Center to the new Billing and Payment group and was told that the reason the transfer of functions had not yet occurred was that the Company was exploring

[REDACTED]

Tr. 64-65 (Nov. 30, 2017).

Thus, the Company's failure to move the credit and collections functions from the Contact Center to the Billing Payment and Group is still unresolved. Not only was this a recommendation from Liberty Consulting that the Company agreed with, it was also recommended by the Commission. Commission Staff find such an abrupt, significant change of plan by the Company without an overall vision or long-term strategy in place problematic. Further, Staff is unclear where this leaves the Company's initial plan to move the credit and collections functions from the Contact Center to the Billing and Payment Group.

In addition, the decision to **[REDACTED]**

Id. at 62.

As part of its Revenue Requirement filing, the Company has proposed a $511,457 adjustment to the test year relating to the new CSR staffing levels. To the extent that Company **[REDACTED]** and such change takes place in the rate effective year, the entire Customer Service revenue requirement will need to be re-visited.

3. Delinquent Accounts

In the Liberty Report, Liberty recommended that the Company take measures to standardize and stabilize the write-off process (recommendation #8) so that the write-offs are processed on the same schedule and that the Company pursue options to act on delinquent active accounts sooner (recommendation #9). *Liberty Report* at III-40. The Commission also found in Docket No. 2015-00360 that CSRs multi-tasking (discussed above) likely lengthened collection times and ultimately caused increases in bad debt expense. *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket No. 2015-00360, Order (Part II) at 50 (Dec. 22, 2016). In its testimony, the Company states that it has reduced the time for a delinquent account to receive a disconnection notice from as long as 90 days to as little as 30 days. In addition, the

Company states it has been requesting payment from delinquent high-balance residential customers through its IVR and field collectors, when call volumes permit. The Company also testified that it is currently exploring options that might allow more consistent application of credit processes. Holyoke Pref. Dir Test. 28.

While the reduced time to issue disconnection notices is a positive step, Commission Staff is nonetheless concerned that the Company has not aligned the disconnection, and ultimately the write-off processes, between the BHD and the MPD so that the processes are on the same schedule. Staff is also concerned that the Company has not fully pursued options in the BHD to act on delinquent accounts sooner. Table 13 below shows the delinquency collection processes for the two divisions.

Table 13

Type of Disconnection	Company Division	Total # of Days to Disc. Date**
Residential Non-Pay	BHD	85
	MPD	77
Residential Broken PA*	BHD	77
	MPD	66
Commercial Non-Pay	BHD	78
	MPD	70
Commercial Broken PA	BHD	77
	MPD	66

**Payment Arrangement*
***# of days from bill issuance to disconnect date*

ODR-001-006, Att. A.

A review of Table 13 shows that MPD acts on its disconnection notices between

8 and 11 days sooner than BHD. Because these processes are not aligned, write-offs between the two divisions will not occur at the same time intervals. In addition, this creates a confusing situation for customer service representatives who must work with the credit and collections functions for both divisions and creates an unnecessary opportunity for mistakes. Because the disconnection process for both divisions is an automated process executed pursuant to the requirements of Chapter 815 of the Commission's rules, there is no reason that the processes should be different between the two Divisions.[19] Further, a review of the BHD's disconnection process shows that it is providing additional days to the process that are unnecessary, lengthening the overall disconnection period.

Staff also finds that the process the Company uses to decide which customer accounts to actually disconnect is governed by the availability and location of field staff needed to perform the actual disconnection, as opposed to the customer specific circumstances such as amount owed and the time period for which the customer has not paid. In response to an oral data request, the Company explained that daily reports are created from its Customer Information System based on the customer's geographic location. The accounts in the reports are listed in highest disconnection dollar amount to lowest disconnection amount, with each report containing between 20 to 30 accounts. Once the reports are generated, however, the Company uses the availability of a field person to decide what customer accounts are disconnected.[20] This is not an efficient means of collecting on delinquent accounts.

[19] Chapter 815, §10(D).
[20] Emera outsources its meter reading functions, including field disconnections, to Grid One.

Staff experienced a recent situation involving a customer that filed a customer complaint against Emera where this approach to field collections may have resulted in a customer account that should have been disconnected at a certain time instead going an extended period of time without action. In this situation, the customer sought CASD assistance after the customer received a bill from Emera for almost two years' worth of electricity at a service address where the customer no longer lived. In this case, the customer did not pay anything on the account after it was established and the post office returned all bills to Emera marked undeliverable. Further, Emera sent 11 disconnection notices to this customer with no response and no payment, yet continued to serve the location. Though Emera could have acted on the any of the 11 disconnection notices sent to this location, it did not. Instead, it allowed the debt to build for almost 2 years to almost $1,000 before acting on the disconnection notice.

Emera Maine staff have indicated to CASD that the Company lacks sufficient field people to complete all eligible disconnections and instead focuses on the largest balance customers and in certain geographic locations first. This can result in some accounts going an unnecessarily long time without being disconnected, which in turn allows the amount overdue to continue to build, as demonstrated by the example above. This in turn increases bad debt and write offs.

E. Billing Errors

The Liberty Audit found that BHD's billing performance had not returned to target levels after go-live in June 2015. Bill error performance fell below target in June 2015 and has been problematic since, as Emera management continues to address CIS-related issues. The Company states in its testimony that it continues to identify billing issues associated with the CU implementation; however, as with any CIS implementation, there will be associated bill errors. The Company goes on to state that it is not unusual or concerning that less obvious errors, with small impact on customers have continued to be identified, even two years after implementation and that this is not necessarily a symptom of a larger problem. The Company acknowledges that its bill error rate is marginally higher than it was pre-CU implementation. Holyoke Pref. Dir Test. 30.

The Company states in its testimony that through the end of August, there have been seven reportable bill error events (requiring reporting to the Commission) in 2017, affecting 6,941 accounts in total with a combined financial impact of less than $20,000.[21] The Company also states that it sees a general downward trend in CU Incidents overall and that this is consistent with the expectations of a maturing system.[22] The Company states that through creation of the Billing & Payment Group to focus on meter to cash function, and by putting a Senior Manager in charge of this function, the Company has taken significant steps to proactively manage bill errors, identifying potential bill errors before bills are sent and avoiding bill errors before they happen. The Company also states that it has also formed a Bill Quality Assurance Team to improve the identification of bill errors and that the team "has been successful in identifying

[21] Section 8(E) of Chapter 815 requires electric and gas utilities to report any bill error that affects more than 10 customers to the CASD.

[22] Emera defines a CU "Incident" as any issue identified for resolution in the CU system.

issues." Holyoke Pref. Dir Test. 31-34. Commission Staff disagrees with the Company's assessment of its billing performance.

First, regarding the Company's statement that it is "not unusual or concerning that less obvious errors, with small impact on customers have continued to be identified, even two years after implementation and that this is not necessarily a symptom of a larger problem," the Commission Staff disagrees that this is not concerning or that it is not symptomatic of a larger problem. Holyoke Pref. Dir Test. 30. A review of Attachment 1 shows that the Company has experienced 32 billing errors affecting 100,815 customer accounts since the implementation of its new CIS in June 2015. ODR-001-014 Attachment A. Further, a breakdown of the 32 errors by date of discovery shows that 11 errors were detected in 2015; 6 errors were detected in 2016; and 14 errors were detected in 2017. This breakdown does not indicate that there's a downward trend in billing errors. In fact, more billing errors were detected in 2017 than in the previous two years. Further, 15,145 customers were impacted by billing errors in 2017 which this is not an insignificant number.[23]

Commission Staff also disagrees with the statement that the Company has been successful in identifying bill errors prior to the bills being issued. A review of the Company's response to EXM-002-040 shows that the quality assurance processes identified in the Company's testimony have identified one billing error prior to bills being issued. While it is positive that this billing error was detected and remedied prior to bills

[23] The data contained in Attachment 1 does not appear to be consistent with the Company's testimony described above regarding the number of billing errors that occurred in 2017 or the number of customers impacted by billing errors in 2017. Commission Staff is unclear as to the reason for this discrepancy.

being issued to customers, considering the fact that the Company has experienced 32 billing errors to date, the discovery of one error is not an indication that the Company has been successfully identifying bill errors prior to the bills being issued. Staff acknowledges that the Billing Quality Assurance Team is relatively new and that the discovery of bill errors may increase.

Commission Staff is also concerned about the amount of time it takes Emera to remedy some billing errors after the errors have been identified. As noted in the Commission's *Order Initiating Management Audit* issued in Docket No. 2015-00360, the Commission's Consumer Assistance and Safety Division (CASD) has had a number of discussions with the Company about billing errors which apparently have occurred as a result of CIS implementation problems. These problems included: failure to produce/send bills; bills not properly dated resulting in incorrect (early) due dates; one time fees put on more than one month's bill; and certain CEP customers being charged twice the state tax due for usage above 750 kWh. The CASD reports that it continues to work with the Company on billing errors and has been frustrated at times with the slowness of the Company's response to some of the errors. In some cases, remedial action by the Company only occurred after the errors were "rediscovered" a second time by the Company. A review of Attachment 1 shows that three errors took over a year to address after discovery and one error took two years to address after discovery.

F. <u>Summary</u>

The Company states at the end of its "Customer Experience Improvements" section of its testimony that "[i]t has addressed those aspects of its service quality that the Commission cited in imposing the Management Efficiency Adjustment. Addressing and correcting the identified deficiencies in service has resulted in delivering the level of service that the Commission indicated was appropriate." Holyoke Pref. Dir Test. 35. Staff disagrees.

As discussed earlier in this analysis, in Docket No. 2015-00360, the Commission established the following three criteria in determining whether service practices were unreasonable or inadequate:

1) whether the company's practice substantially departs from the regular and accepted practice of the company in question as well as that of other utilities in general;
2) whether benefits to the company of the practice are outweighed by the adverse impact of the practice on its ratepayers; and
3) whether the company's practice results in inadequacy of service when considering such factors as the number of customers affected, the duration of the impact, the reason for the company's action and the departure from historic trends.

Hogan v Hampden, supra. 36 PUR 4th at 485.

Regarding the Company's call answer performance, while there has been improvement in Emera's call answering performance, it is Staff's position that Emera needs to demonstrate that it can meet the 80/30 standard on an annual, as well as an on-going, basis before Staff can recommend a finding by the Commission that Emera's service as it relates to its call center operations meets the criteria above.

Regarding the Company's service related to its credit and collections, it is Staff's position that the Company is not meeting the criteria above at this point. As noted previously, the Company has not aligned the disconnection and the write-off processes between the BHD and the MPD so that the processes are on the same schedule. Further, the Company has not fully pursued options in the BHD to act on delinquent accounts sooner, thus potentially increasing uncollectibles and bad debt. Collecting revenues for service provided is a fundamental aspect of utility service and an aspect that all utilities are required to perform well. It is Staff's position that Emera is not performing this function consistent with generally accepted practices and practices of other utilities in general. Thus, the Company fails to meet criteria #1. Further, increasing uncollectibles and bad debt associated with accounts not being disconnected in a timely way ultimately falls to the responsibility of other rate payers. In this way, all customers of the utility are affected in a negative way by increasing bad debt. Thus, the Company fails to meet criteria #3.

Regarding the Company's service related to billing, it is Staff's position that the Company is not meeting the criteria above at this point. Issuing accurate bills to customers in a timely and consistent manner is a fundamental aspect of utility service and an aspect that all utilities are required to perform well. As discussed, Emera continues to have problems issuing accurate bills on a routine basis. It is Staff's position that Emera is not performing this function consistent with generally accepted practices and practices of other utilities in general. Thus, the Company fails to meet criteria #1. Further, because Emera's billing errors have impacted over 100,000 customers in the past two and half years and over 15,000 customers to date in 2017, the Company fails to meet criteria #3.

IV. CUSTOMER SERVICE AND OPERATIONS TECHNOLOGY INVESTMENT

A. Company Request

In its Customer Experience testimony, the Company lays out its current technology plans as well as some of its near and longer term thoughts and goals. In its Operations and Reliability testimony, the Company reveals its budget plans for its GIS IT project. Some of the items discussed have cost estimates, while others are in the preliminary planning stages.

In terms of planned spend for this rate case, there are three large IT projects totaling approximately $11 million which the Company is asserting will be operational in the rate effective year, or reflect actual O&M costs during the rate effective year. Specifically, the Company has identified an upgrade for the Cayenta Utilities CIS (CU-CIS) (estimated $6.1 million), a deployment of “Bill Advisor” with some minor interface upgrades to provide high bill alerts, energy insights and an accompanying CSR tool ($675,000), and GIS upgrades to allow improved distribution planning and outage management ($2 million). In addition, the Company is making the “slightly untraditional” request of $2.1 million dollars for an “’undesignated Customer Experience Capital Fund’ intended for a menu of customer value creating options the Company intends to implement”. Holyoke Pref. Dir. Test. KH-42.

A summary of these initiatives and their location within the testimony can be seen in Table 14 below.

Table 14

Page Location	Description	Dollars requested
Customer Service Projects with Cost Estimates		
KH-35,36	Upgrade CU to "include important enhancements that are only accessible with the upgrade".	$6.1 million
KH-40	"Bill Advisor" also referred to as "OPower project" (High bill alerts, energy insights and CSR high Bill Call tool)	$675,000
KH-41-42	Planned "account portal usability". This is part of the "Bill advisor" project	
KH-41-42	Enhance web-based payment This is part of the "Bill advisor" project	
Projects for "undesignated Customer Experience Capital Fund"		
KH-42-44	POTENTIAL projects (KH-42, 43) • Customer mobile or web self service • Two-way texting for outage notification and bill payment • "Customer Self Service Portal" • "Enhanced Outage Map" (goal to implement in 2018/2019—doesn't show in "technology plan") • "Text Outage Notifications" • "improve outage communications by rolling out a new improved internal estimated time of restoration processWITH text ability. (AFTER Upgraded outage management system -see "tech plan" for timing) • Customer Comms Preference Portal so customer can select their comms preference • Bill redesign	$2.1 m/year for capital investment
	Programs in progress/planning: • P. kh-22, line 19-23: "Voice of the Customer" tool. • P. KH24-25, IVR capital spend still in planning mode, and a planning estimate has been established. • KH-38 MPD upgrade • "Screen Pops" • KH-23 IVR System restructure (currently in progress, In 22, and scheduled to be in service 3/2018)	

Operations IT Projects With Estimates		
RB-42-43 and EXM-004-46 EXM-004-47	Software Projects • Upgrade existing GIS software • Outage Management/PowerOn integration • GIS/Cyme interface upgrade Data updating	$2 million

The Company asserts it has learned its lessons from the CU-CIS which has helped improve their scoping and budgeting of major IT projects by relying more on outside experts to develop cost and schedule estimates.

B. Overview Staff Response

Staff is not confident that these projects will successfully be completed and useful as projected, or that the Company has made meaningful changes in its planning processes that will help to increase the reliability of its projections. Therefore, Staff recommends excluding all of these requests from the revenue requirements until such time as implementation is complete. Staff's lack of confidence is based on the conclusion that: the Company lacks a five-year customer service plan with goals; and the Company's technology plan as provided to Staff in this case lacks any substance.

1. The Company Lacks a Five-Year Customer Service Plan with Goals

As discussed in Section III of this analysis, in the last rate case the VP of Customer Experience was in the midst of a long process defining a five-year vision for the department. In testimony in this case, Ms. Holyoke asserts:

> Originally, Emera's goal was to deliver a formal five-year strategy and plan late last year. However, the current approach to the strategy is an ongoing, iterative process.

> Emera's vision for customers' experience is to be responsive to what customers want today, and tomorrow: Customers *count on us* and we need to deliver Control, Choice, Convenience and Communication...However, the completion of a formal five-year plan is on hold until certain technology plans are formulated regarding the customer information system in the MPD.

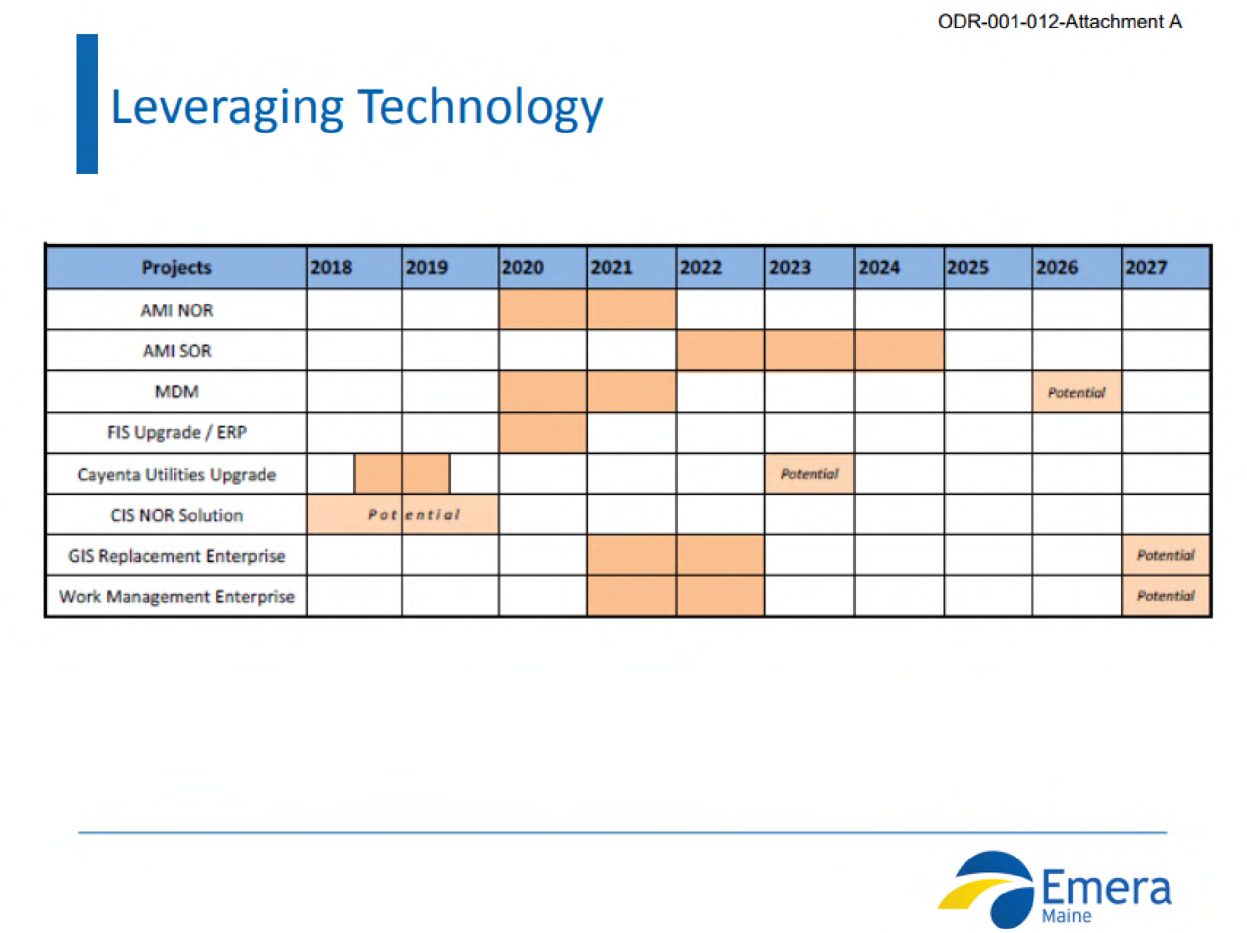
Holyoke Pref. Dir. Test. KH-11 (emphasis in original).

This statement appears to indicate that the technology plan would drive the business plans. This directly contradicts the learning **[REDACTED]** When asked about the decision-making criteria on these crucial IT and business decisions, the Company said there is no decision matrix and offered no further decision-making criteria. EXM-002-009. In order for the Commission to evaluate whether a decision was well-considered, an understanding of the rationale and criteria for that decision is critical. As a starting point, knowing the five-year business plan is helpful for evaluating technology decisions. As the Company's consultant recommends, business decisions should be taken before technology projects.

Ms. Holyoke's testimony also calls into question the Company's focus to perform their basic regulatory obligations at a "reasonable cost". In its testimony, the Company has provided no evidence of any sort of cost-benefit analysis around any of these initiatives that would suggest potential benefits to the Company from an efficiency, staffing, safety and reliability nor how they benefit the customer in the form of lower rates, increased service levels or increased reliability.

2. The Company's Technology Plan as Provided to Staff in This Case Lacks Any Substance.

During the technical conference, while trying to develop an understanding of how the Company evaluates projects and understands how to make technology choices, Emera pointed to its technology plan. Tr. 128-130 (Nov. 30, 2017). In response to ODR-001-012, the Company provided the plan which is reproduced below in its entirety.



This technology plan provides little guidance for making major decisions. The Technology Plan does not, for example, address when major software upgrades can be expected, how those upgrades are expected to impact the various systems in use, and what type of hardware upgrades may be needed. These are only a few of the issues a well-developed technology plan or IT roadmap should address.

C. CIS History Implementation and Upgrade

In 2011, the Company made a decision to move its Bangor Hydro customers to a new Cayenta Utilities Customer Information System (CU-CIS). In June 2014, the Commission approved a settlement which, *inter alia,* included approximately $13 million of costs in distribution rates based on an original $19.7 million estimate with an imminent in-service date. On June 8, 2015, one and one-half years later than planned and at a cost of over $30 million, CU-CIS went live. Holyoke Pref. Dir. Test. KH-8

The Company asserts that “CU continues stable performance, within the parameters expected.” *Id.* at 9. However, it continues “to identify billing issues associated with the CU implementation”, and that even though “[t]he bill error rate is marginally higher than it was pre-CU implementation”, their “experience today is one of generally strong performance.” Holyoke Pref. Dir. Test. KH-31. When asked what the performance parameters expected were, the Company responded that there were no “specific set of performance factors.” EXM-003-005.

To maintain its investment in its new system, Emera Maine is proposing an upgrade projected to take up to 12 months and approximately $6.1 million ($5.5 million to $7.75 million excluding AFUDC and markup). In its testimony, Emera Maine asserts that the upgrade is “a key part of the important maintenance for an essential system . . . and it will also include some important enhancements that are only accessible with the upgrade.” *Id.* at KH-35 to KH-36. While describing the upgrade and enhancements, the Company asserts “[t]he focus for the upgrade is not additional functionality but to ensure this key system is current and supported by the vendor.” As of the November 30 Technical Conference, no RFP had been issued nor was the VP of Customer

Experience certain how long it would take to issue the RFP and select the vendor before commencing the 12-month project. Tr. 149 (Nov. 30, 2017).

Staff has a number of concerns about the cost, timing and implementation of this upgrade as well as its necessity. In response to ODR-001-017, the Company declined to provide evidence of the "robust discussions" or any of the other considerations around the decision to postpone the upgrade and how long would be prudent to do so. Staff would have expected some documentation which showed at least some discussion of some of the following topics: the consequences of not upgrading, including CU choosing to no longer support a given version, current features and functions at risk of being lost for lack of upgrade, interaction with upgrades of other systems that interact with CU. Staff would also have expected some conversation about the benefits of the upgrade such as what further automation could be enabled, what features in the business' longer range plans could be enabled by the upgrade, etc.

Based on the Company's past implementation record and the responses received in the technical conference, it is not clear to Staff that the project will be useful and operational within the rate effective year. In the best-case planning scenario, the upgrade will be in service one month before the end of the rate effective year. When this is combined with the Company's track record regarding the implementation of the CU-CIS, Staff recommends excluding the $6.1 million requested in this rate case. The Company can, of course, ask for it in the next rate case and defend its logic and prudence at that time.

D. <u>CIS and Maine Public District</u>

According to Company testimony, a recent review has indicated that moving the MPD customers to CU-CIS would likely cost about $18 million. As a result, the Company is actively considering two alternatives in an effort to find a lower cost solution:

- a “wrap”, or “extender”, which would pull data from MPD’s AS400 system and CU-CIS to a single interface for CSRs; or
- an approach similar to that used for Swan’s Island customer where all new records are created in CU over time.

The Company anticipates completing this review of options by the end of 2017, and has not made a specific request for money related to this project in this rate case.

Staff is generally supportive of the Company’s efforts to find lower cost solutions. However, Staff also cautions that it is difficult to assess the prudence of the Company’s actions because in this record it remains unclear exactly what other low-cost alternatives may have been considered and rejected before directing the current exploration.

E. <u>Customer Experience and Technology</u>

1. Bill Advisor

To provide better and more timely information to customers about their bills, including proactive alerts, the Company has engaged OPower/Oracle in a contract for the Opower “Bill Advisor” tool. The project will provide three enhancements: two for customers and one to help CSRs better navigate the new information. The three enhancements are: High Bill Alerts, Energy Insights and CSR High Bill Call Tool. The contract is for an initial $545,000 and a subsequent $250,000 per year license fees. In addition, parts of implementing the Bill Advisor tool will require some “targeted” changes to the website, as well as with the billing and payment vendor, Kubra. These are anticipated to be an additional $130,000 in capital costs. Holyoke Pref. Dir. Test. KH-41 to KH-42

It is not clear to Staff why this large project, Bill Advisor, was chosen over any of the smaller projects which the Company has mentioned as possible investments. For Staff to effectively analyze this expense’s prudency it would help to know what criteria the Company used to make this decision including, as a partial list, the expected ROI, the expected improvement to customer satisfaction, and how that will be measured.

Staff recommends that these costs not be included in revenue requirements at this time. The costs for these yet to be offered programs do not qualify for inclusion as known and measurable changes. The Staff, therefore, proposes that the costs that Emera has included in the rate year revenue requirement associated with the Bill Advisor Programs be removed.

2. Interactive Voice Response (IVR) System Restructure

In its testimony, the Company explains that the IVR allows customers to obtain information about their account without needing to speak to a CSR. Therefore, it is an efficient way to meet customers’ needs and reduce call volume. Both, the Liberty Report and Emera Maine’s own third party consultants have indicated that the Emera IVR would benefit from a restructure. To that end, Emera has engaged the IVR Doctors for help on this redesign. In addition to developing intuitive, customer-friendly, jargon-free phone menus, the Company hopes to enable “Virtual Hold” (allows a customer to leave their number, holding their queue position for the system to call them back when it is their “turn”) and skill based routing. The Company’s testimony suggests that most, though not all, of this scope is scheduled to be operational by March 2018. The Company states that a substantial amount of the consulting work was completed in 2017 **[REDACTED]** as shown in Exhibit KH-3 and will not be included in this rate case. Holyoke Pref. Dir. Test. KH-24. EXM-004-041, Attachment F (2018 Capital Expenditures) indicates that the capital costs associated with this redesign which will be put into rate base are $308,000 which includes the [**REDACTED]** in Exhibit KH-3. Staff does not have any objection to the work being done, per se, but wants to ensure the IVR restructure will be used and useful during the rate effective year.

F. Undesignated Customer Experience Capital Fund

In its testimony, the Company lists several projects which it could implement, but has not yet decided upon. These include: Customer Mobile, enhanced communication options like two-way texting and the option to tell the Company which of these new modes of communication the customer prefers. The Company claims they will not be able to decide from their wish list until after a decision has been taken on CU-CIS in the MPD.

As a solution to this dilemma, the Company suggests a $2.1 million “undesignated Customer Experience Capital Fund”. As justification for this unusual request, Ms. Holyoke states “Such investment is analogous to the concept of a T&D

Base Capital, where the Company does not have specific plans to spend the Base Capital Budget but based on conditions as they develop . . ..” Holyoke Pref. Dir. Test. KH-43.

Staff believes the Company has erred in its analogy and its focus with this request. Ms. Holyoke’s testimony mistakes the basis for the base capital in the T&D budget. Distribution planning has a full suite of inspections that identify issues, the reliability manager then prioritizes the improvements based on known, quantifiable data. Customer Experience division has neither proposed anything approaching that rigor, nor demonstrated anything approaching that rigor in this rate case.

Additionally, it’s not clear to Staff that the focus on this broad array of technology additions is appropriate given the number of other issues facing the Company’s management as well as the Company’s current rate levels and other pressure on such rates. Therefore, Staff recommends not allowing this into rate base.

G. GIS Investments

The Company proposes approximately $2 million worth of capital projects to go into revenue requirement with a surprisingly low level of certainty. In “Distribution and Operations Reliability” testimony, the Company explains that to “increase the efficiency of distribution planning processes”, the Company plans a two-step process of improving software and fully integrating it into the MPD. The first step, “improving software” is important because it will allow real-time integration of GIS information. In order to make this feature useful, GIS data needs to be updated (the second step). Belliveau Pref. Dir.

Test. RB-42 to RB-43

In EXM-004-046, the Company provides further detail about three specific software projects that Emera is “contemplating”:

- Upgrade existing GIS software to a new (though not current) version ($618,000 budget in 2018 rate effective year)
- Outage Management System improvement to PowerOn which would allow integration between the two systems. ($462,000 budget in 2018 rate effective year)
- GIS/Cyme interface upgrade. Cyme is the software used for distribution system analysis. This upgrade will decrease the necessary manual manipulation, will reflect in Cyme immediately. ($250,000 considered for second half of 2019)

In addition to the software projects listed above, the information within the GIS database needs to be updated as well. Currently, the Company does not have all its equipment, particularly in MPD, logged into a central GIS system. In EXM-004-047, the Company explains that they are considering the most efficient way of doing this to be engaging an outside contractor for $650,000 (including AFUDC and overhead)

It is unclear from looking at the Company’s Technology Plan, that the timing of this project ties in with the “GIS Replacement Enterprise”.

Additionally, it is not clear that these projects will even be able to be implemented within the rate effective year. As the testimony indicates, these are still uncertain projects and require further scoping. In this testimony, we have not seen indication of a clear rationale or any type of analysis of cost-effectiveness and impact on reliability or customer. For these reasons, Staff recommends excluding these expenditures from the revenue requirement.

V. COST OF CAPITAL

A. Emera Maine Request and Testimony

The Company's filing includes a request to remove the 50 basis point management efficiency adjustment imposed in the last rate case and set the allowed return on equity (ROE) at 9.50%. Emera Maine's cost of equity witness, John Perkins, develops a current cost of equity in the range of 10.00% to 10.40% and recommends an ROE of 10.20%.

In developing his recommendation, Mr. Perkins first identifies a peer group of utilities and then employs a number of methodologies to estimate Emera's ROE, including the Discounted Cash Flow (DCF) model (using a Constant Growth and Multi-Stage form), the Capital Asset Pricing Model (CAPM) (using a standard CAPM model and an empirical CAPM model), and a risk premium approach (using a Bond Yield Risk Premium model and a Predictive Risk Premium Model).

The Company computes a weighted average cost of capital (WACC) of 10.45% using a common equity ratio of 49.00%, long-term debt equal to 47.03% of total capital, short-term debt at 3.91% of total capital and preferred stock at 0.06% of capital, each component at the cost as shown in Table 15 and with the equity returns grossed up to reflect the Company's combined federal and state income tax rate. Mr. Perkins states that Emera Maine's proposed capital structure is generally consistent with the capital structure of the proxy group companies and consistent with the imputed capital structure that was accepted in the Company's last two distribution rate cases.

Table 15

Emera Maine Capital Structure, Costs and ROE

Emera Maine as Filed						
Weighted Average Cost of Capital						
Capital Structure		**Ave. Balances**	**Ratios**	**Rate**	**Cost**	**Pre-Tax WACC**
						Tax Gross up 40.8045%
Long-Term Debt		287,694,662	47.03%	5.18%	2.44%	2.44%
Short-Term Debt		23,909,833	3.91%	3.96%	0.15%	0.15%
Preferred Stock		365,400	0.06%	7.00%	0.00%	0.00%
Common Stock		299,700,000	49.00%	9.50%	4.65%	7.86%
		611,669,895	100.00%		7.25%	
		Pre-Tax Weighted Average Cost of Capital				**10.45%**

B. Hope-Bluefield Standard

Two United States Supreme Court decisions of more than 70 years ago, known as the *Bluefield* and *Hope* cases, provide the standards for measuring the reasonableness of a utility's allowed ROE. Taken together, the *Hope-Bluefield* decisions establish that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made…on investments in other business undertakings which are attended by corresponding risks and uncertainties…The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public

duties.

Bluefield Water Works and Improvement Co. v. Pub. Serv. Comm'n of West Virginia, 262 U.S. 679, 692-3 (1923).

Additionally, the idea of associating the allowed return to a common equity owner with those available from other companies of comparable risk was established in the *Hope* decision:

> [T]he return to the equity owner should be commensurate with the return on investment in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591,603 (1944).

Thus, the practice of determining an appropriate ROE for a company that is not publicly traded such as Emera Maine is one that involves developing a comparable group of companies, for which market-based information is available, that are in the same business and that present similar financial risks.

C. <u>Proxy Group Selection</u>

In his testimony, Mr. Perkins followed a customary approach for selecting a proxy group of publicly traded utilities which are representative of the risks and prospects faced by Emera Maine. Beginning with a group of 40 domestic utilities classified by Value Line as Electric Utilities, he applied reasonable and widely used screening criteria to include only companies which:

a. Consistently pay quarterly cash dividends;
b. Are covered by at least two utility industry equity analysts;
c. Have investment grade senior bond or corporate credit ratings;

d. Have regulated operating income over the three most recent years of at least 60%;
e. Have regulated electric operating income over the three most recent years of at least 60% of total regulated operating income; and
f. Are not currently a party to a merger or other significant transaction.

Staff is generally in agreement with the screening criteria used by Mr. Perkins but recommends the elimination of three companies in his proxy group based on specific issues. Hawaiian Electric Industries, Inc. owns both Hawaiian Electric Company and American Savings Bank. In 2016, the banking operations represented 12% of consolidated revenue and more than 20% of consolidated operating income. Staff does not believe that a company with such a sizeable banking operation represents a comparable risk profile to Emera Maine. Staff also has removed SCANA and Southern Company from the proxy group. Utility subsidiaries of both companies have significant exposure to troubled nuclear construction projects being built by Westinghouse Electric Company, the outcome of which is undetermined at this point.[24]

Additionally, Staff has concerns about using a 60% threshold for regulated operating income. The application of a 60% regulatory revenue screening criteria has the effect of including companies that derive a significant portion (up to 40%) of their

[24] Westinghouse Electric, the primary construction contractor and designer of nuclear projects being built by subsidiaries of SCANA and Southern Company, filed for bankruptcy in late March because its corporate parent, Toshiba, suffered huge losses on the projects in Georgia and South California. SCANA's subsidiary, South Carolina Electric & Gas, terminated the construction of the VC Summer nuclear plant in South Carolina in August. Southern Company's subsidiary, Georgia Power, is continuing development of its Vogtle project in Georgia even though it is currently $10 billion over budget and three years behind schedule. Both companies continue to pursue claims in the Westinghouse bankruptcy proceeding. See, e.g. *Southern Company Sets Deadline for Toshiba's Pending Payment*, available at http://www.nasdaq.com/article/southern-company-sets-deadline-for-toshibas-pending-payment-cm887431.

operating income from non-regulated or competitive business enterprises that do not bear similar risk profiles to Emera Maine. In past Emera Maine rate cases, Staff has recommended using a 90% threshold for this screen. Based on the information provided by Mr. Perkins in response to EXM-003-001, five remaining companies would fall below the 90% screen, two are below 80% (Otter Tail and Wisconsin Energy) and three are below 90% but above 85% (ALLETE, Ameren and Dominion). To ensure that the proxy group remains large enough to provide useful information, Staff has employed an 85% threshold for this screening criterion.

As a result of the above adjustments, Staff's final proxy group is as follows:

Table 16
Staff Final Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Black Hills Corporation	BKH
CenterPoint Energy, Inc.	CNP
CMS Energy Corporation	CMS
Consolidated Edison, Inc.	ED
Dominion Resources, Inc.	D
DTE Energy Company	DTE
Duke Energy Corporation	DUK
El Paso Electric Company	EE
IDACORP, Inc.	IDA
Eversource Energy	ES
NorthWestern Corporation	NWE
OGE Energy Corp.	OGE
Pinnacle West Capital Corporation	PNW
PNM Resources, Inc.	PNM
Portland General Electric Company	POR
Xcel Energy Inc.	XEL

D. Constant Growth DCF Model for Estimating Cost of Equity

Consistent with past Commission practice and orders, the Staff (and Mr. Perkins) employ a discounted cash flow (DCF) approach to the cost of equity analysis.[25] The DCF model is commonly used for estimating the cost of common equity for public utilities and is based on the financial theory that the value or price of any security is the discounted present value of all future cash flows. As explained in materials published by the Society of Utility and Regulatory Financial Analysts:[26]

The DCF model is based upon two fundamental principles.

[25] *See. Central Maine Power Company, Proposed Increase In Rates*, Docket No. 92-345, Order at 31 (Dec. 14, 1993).
[26] Parcell, David C. The Cost of Capital—A Practitioner's Guide, at 124, Society of Utility and Regulatory Financial Analysts, 2010 Edition.

> First, DCF is based on the postulate that investors value an asset on the basis of the future cash flows (i.e., dividends and ultimate sales in the case of common stocks) they expect to receive from owning the asset. The second DCF principle is that investors value a dollar received in the future less than a dollar received today (i.e., the "time value of money"). Within this context, the current price of a company's stock is equal to the present value equivalent of the expected dividends and the proceeds from eventually selling the stock. The discount rate that equates the future anticipated dividends and the future anticipated selling price with the current market price is the cost of common equity.

In its very simplest form, a DCF estimate of the cost of equity capital uses the formula

$$K=D/P + g$$

where:	K =	cost of equity capital
	D/P =	dividend yield (dividend payout/stock price)
	g =	long-term expected growth rate

Generally, the market based data (market prices and current dividends) required to conduct any DCF analysis are readily available.

A key component of the DCF formulation is the long-term expected future growth rate. A common method of estimating future growth is to use growth rates in earnings per share projected by securities analysts who follow the stock of the proxy group companies. In his constant growth DCF analysis, Mr. Perkins derives a range of indicated ROE by using growth rates equal to the maximum, the mean, and the minimum of long-term earnings growth rates projected by securities analysts. The growth rates used in Mr. Perkins's single stage growth DCF analysis range from 1.50% to 9.00% for individual companies and are used as a basis for establishing the high end and the low end of the ROE range.

In conducting its constant growth DCF analysis, for the long-term expected growth component of the formula (g), Staff used two different long-term expected growth rates in an effort to derive a range of indicated ROE, the average of the analysts five-year earnings growth rates as reported on YahooFinance! on December 11, 2017 (5.03%) and the average earnings growth used by Mr. Perkins, adjusted to exclude the companies identified above from the proxy group (5.31%).

1. Staff DCF Analysis-Constant Growth Model

The actual DCF calculations as provided in Attachment 2 are largely self-explanatory. To summarize, the current quarterly dividend for each utility as of December 11, 2017, was converted to a forward dividend, assuming that future dividend increases will be evenly distributed over calendar quarters. Thus, the forward dividend for each company is equal to the current dividend increased by one-half of the growth rate for that company. Staff calculated the dividend yield component of the model by dividing the resulting forward dividend by the share price for each utility.

In recognition of the day-to-day variability in closing share prices, we employed the closing market price for each of the proxy group companies as well as a 50-day moving average of closing share price and a 200-day moving average of closing share price for each utility as reported by Yahoo! Finance on December 11, 2017. This resulted in a range of current dividend yield calculations for the entire proxy group, from a low of 2.17% to a high of 4.12%, averaging 3.05%. Staff then added the growth rates as discussed earlier to the low, mean and high dividend yields to achieve an indicated range of estimates of ROE.

As shown in Table 17 below, the constant growth DCF model produces an indicated ROE range of 7.20% to 9.43%.

Table 17
Constant Growth DCF Model
Indicated ROE

		Indicated ROE Range		
Constant Growth DCF Indicated ROE	**Growth Rate**	**Low**	**Mean**	**High**
Average Analyst Growth (YahooFinance)	5.03%	7.20%	8.08%	9.15%
Perkins average (3 Analyst average)	5.31%	7.47%	8.35%	9.43%
	Min	Max	Mean	
Range:	7.20%	9.43%	8.31%	

2. DCF Analysis-Multi Stage Growth Model

In addition to this constant growth DCF model, other formulations of the DCF model that assume different growth rates over future time periods (multi-stage growth) can be used. Mr. Perkins employed a multi-stage (three-stage) DCF analysis, which allows different growth rates to be specified for different time frames. For the initial growth stage, Mr. Perkins used the same analysts' growth rates and retention growth rate as used in the constant growth DCF model. For the long-term, Mr. Perkins incorporated two different approaches, one used a long-term GDP nominal growth rate of 5.34%, based on the real GDP growth rate of 3.22% from 1929 through 2016 and an inflation rate of 2.05%; the other approach incorporates a long-term expected payout ratio and price earnings ratio (the Gordon model). The medium-term growth rate is a transition from the short-term to the long-term growth rate. As stated in his testimony at

JP-30, Mr. Perkins relied primarily on the Gordon model calculations, which produces an indicated ROE range of 9.51% to 10.79%. Additionally, Mr. Perkins included the results of his calculations using the long-term GDP growth rate, which produces an indicated ROE range of 8.64% to 9.13% (Exhibit JP-2a). As with his constant growth DCF model, Mr. Perkins derives the range by using the individual high and low long-term growth estimates for the initial stage growth component.

Staff also conducted a multi-stage DCF analysis based on the two-step DCF methodology employed for several years by the Federal Energy Regulatory Commission (FERC) in determining ROE for natural gas and oil pipeline industries and recently extended to the electric utility industry.[27] In describing its two-step methodology for determining the growth component, FERC explained:

> The Commission uses a two-step procedure for determining the constant dividend growth component of the model, averaging short-term and long-term growth estimates. Security analysts' five-year forecasts for each company in the proxy group, as published by the Institutional Brokers Estimate System (IBES), are used for determining growth for the short term; earnings forecasts made by investment analysts are considered to be the best available estimates of short-term dividend growth because they are likely relied on by investors when making their investment decisions. Long-term growth is based on forecasts of long-term growth of the economy as a whole, as reflected in GDP. The short-term forecast receives a two-thirds weighting and the long-term forecast receives a one-third weighting in calculating the growth rate in the DCF model.[28]

As provided in Attachment 3, Staff calculated an indicated ROE based on a long-

[27] Martha Coakley, Massachusetts Attorney General, et. al. v. Bangor Hydro-Electric Company, et. al. opinion No. 531, "Order on Initial Decision", 147 FERC ¶ 61, 234 (June 19, 2014).
[28] *Id*. ¶ 17.

term growth rate calculated consistent with the FERC methodology; that is, a two-thirds weighting of the analysts forecast of short-term growth and a one-third weighting based on the long-term growth of the economy as reflected in GDP. In calculating this weighted growth rate, Staff used a GDP growth rate of 5.34%, the rate utilized by Mr. Perkins. The low, mean and high dividend yield calculations are the same as in the constant growth DCF model. The two-stage DCF model produces an ROE range of 7.30% to 9.25%.

3. Capital Asset Pricing Model

As the Commission has previously recognized, results from an analysis using the Capital Asset Pricing Model (CAPM) provide a useful check on the DCF analysis.[29] The general idea behind CAPM is that investors need to be compensated in two ways: time value of money and risk. The time value of money is represented by the risk-free (Rf) rate in the formula and compensates the investors for placing money in any investment over a period of time. The other half of the formula represents risk and calculates the amount of compensation the investor needs for taking on additional risk. This is calculated by taking a risk measure (beta) that compares the returns of the asset to the market over a period of time and to the market premium (Rm-Rf).[30]

The general form of the CAPM is:

$$K = R_f + \beta\,(R_m - R_f)$$

where: R_f = risk free rate
R_m = return on market

[29] *Central Maine Power Company, Proposed Increase In Rates*, Docket No. 92-345, Order at 31 (Dec. 14, 1993).

[30] http://www.investopedia.com/terms/c/capm.asp

β = beta
$R_m - R_f$ = market risk premium

As a check to the results of the DCF analysis, Staff conducted a CAPM analysis using the Bloomberg and Value Line average beta which was used by Mr. Perkins, adjusted to the revised proxy group. Mr. Perkins's CAPM analysis includes an expected market return component on the S&P 500 Index using the constant growth DCF formulation. He derives both the current dividend yield and the long-term growth factors for the S&P 500 as a whole by weighting the individual company dividend yield and long-term growth by the proportion of total market capitalization that each company represents. Mr. Perkins employs a current 30-year Treasury rate of 2.85%, a near term projected 30-year Treasury rate of 3.35%, and a long term projected 30-year Treasury rate of 4.40% as the risk-free rate. Mr. Perkins's CAPM calculations result in an indicated ROE range of 8.94% to 12.23%. Staff has not included the results of the ECAPM analysis provided by Mr. Perkins in this range.

Consistent with the Commission's preference as indicated in Docket No. 97-580, Staff used a current Treasury rate rather than a forecast of interest rates.[31] Staff calculated the most recent 30-day average of the 30-year Treasury rate and used 2.78% as the risk-free rate.[32] Staff has no issue with the methodology used by Mr. Perkins in calculating market parameters based on the S&P 500 and used the model provided by Mr. Perkins with the revised risk free rate to re-calculate the market risk

[31] *Public Utilities Commission, Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design*, Docket No. 97-580, Order (Mar. 19, 1999).
[32] The average was calculated based on the most recent 30 business days as of December 11, 2017, as reported in Federal Reserve Economic Data (FRED).

premiums. The results of Staff's CAPM analysis indicates an ROE range of 8.90% to 10.70% as shown in Table 18 below. Though this range is higher than the DCF ranges calculated in the previous sections, there is substantial overlap which helps it to serve as an effective double-check.

Table 18

CAPM Results

CAPM	Risk Free Rate	Beta Coefficient	ROE (Bloomberg derived)	ROE (Value line derived)
Bloomberg beta	2.78%	0.58	8.90%	9.32%
Value Line beta	2.78%	0.70	10.19%	10.70%

E. Recommended ROE

In determining its ROE recommendation, Staff depends primarily on the DCF analysis and uses other analyses as a check on the range. The DCF analyses presented by the Staff and the DCF and CAPM analyses presented by the Company produce an indicated ROE that generally falls in the mid-to-high 8% range. The CAPM analysis presented, suggests a slightly higher ROE range, from the high 8% to 10.7%. These results are summarized in Table 19 below.

Table 19

Indicated ROE Range

	Low	High	Mid-point
Staff Constant Growth DCF	7.20%	9.43%	8.32%
Staff Two-Stage Growth DCF	7.30%	9.25%	8.28%
Perkins Constant Growth DCF (Overall)	7.61%	9.40%	8.51%
Perkins Constant Growth DCF (w/o low mean)	8.49%	9.40%	8.95%
Perkins Three-Stage DCF (GDP Growth model)	8.64%	9.13%	8.89%
Perkins Three-Stage DCF (Gordon model)	9.51%	10.79%	10.15%
Perkins CAPM (Current long-term treasury rate)	8.94%	10.69%	9.82%
Staff CAPM	8.90%	10.70%	9.80%

Market expectations are at the core of utility cost of equity analysis and, because the DCF and CAPM analytical approaches are market-based, these results reflect the full range of market expectations. Mr. Perkins provides testimony regarding the expectations for future interest rate increases, the effects of the Federal Reserve's market intervention policies over the past several years and the inherent volatility in equity markets, suggesting that the Commission should incorporate these factors into its ROE determination. A cost of equity analysis done at a particular point in time could be misleading if the underlying market data and results were an aberration. Current equity market conditions do not, however, appear to be an aberration. As noted by Federal Reserve Chair Janet Yellen at her December 13, 2017 press conference, the increases in the stock market this year do not necessarily suggest that the equity markets are overvalued and she does not expect significant upcoming changes to financial markets.

> CHAIR YELLEN. Okay. So let me start, Steve, with the stock market generally. I mean of course the stock market has gone up a great deal this year, and we have in recent months characterized the general level of asset valuations as elevated. What that reflects is simply the assessment that looking at price earnings, ratios, and comparable metrics for

> other assets other than equities, we see ratios that are in the high end of historical ranges. And so that's worth pointing out. But economists are not great at knowing what appropriate valuations are. We don't have a terrific record, and the fact that those valuations are high doesn't mean that they are necessarily overvalued. We are in a, I've mentioned this in my opening statement, and we've talked about this repeatedly, likely, a low interest rate environment lower than we've had in past decades, and if that turns out to be the case, that's a factor that supports higher valuations. We're enjoying solid economic growth with low inflation, and the risks in the global economy look more balanced than they have in many years. So I think what we need to and are trying to think through is if there were an adjustment in asset valuations with the stock market, what impact would that have on the economy and would it provoke financial stability concerns. And I think when we look at other indicators of financial stability risks, there's nothing flashing red there or possibly even orange. We have a much more resilient, stronger banking system, and we're not seeing some worrisome buildup in leverage or credit growth at successive levels.

Transcript of Chair Yellen's Press Conference, December 13, 2017 at 10-11.[33]

Based on this analysis, Staff does not support an ROE of 9.50% as requested by the Company. A 9.50% ROE would fall slightly above the top of the range indicated by the DCF analyses and substantially above the mid-point. Staff is cognizant of the effect that the recent equity market price increases have had on the DCF calculations, specifically with respect to calculating dividend yield. All other things being equal, as market prices increase, the dividend yield and the resulting ROE go down. Based on the DCF analysis alone, an appropriate ROE may be in the range of 8.50%. As noted, however, the Commission uses the results of the CAPM analysis as a useful check on the DCF results. In this case, the DCF and the low-end of the CAPM results overlap and indicate an ROE that would fall at approximately 8.90%. With the addition of a

[33] Press conference transcript available at: https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20171213.pdf

flotation cost adjustment of 9 basis points as discussed below, Staff recommends an ROE of 9.00%. As discussed later, however, the overall management efficiency of Emera Maine may not warrant authorizing an ROE that places the Company at the mid-point of the indicated range. The Commission may continue to impose some or all of the management efficiency adjustment to the indicated ROE.

F. Capital Structure

The Company proposes a capital structure that consists of 49.0% common equity, 0.06% preferred, 47.03% long-term debt, and 3.91% short-term debt. Mr. Perkins's testimony includes calculations based on their utility subsidiaries showing that the proxy group average capital structure is 50.78% common equity, 0.32% preferred, 46.46% long-term debt and 2.44% short-term debt. Additionally, he provides SNL data indicating that the average equity ratio for rate case decisions in 2015-2017 was 49.89%. Staff agrees that the use of a 49% common equity ratio is consistent with common equity ratios in the electric industry and with the capital structure approved in Emera Maine's most recent rate case and is reasonable.

G. Cost of Short-term and Long-Term Debt

The Company's filing includes calculation of the expected cost of long and short-term debt. For long-term debt, Emera Maine incorporates the effect of retirements and sinking fund requirements associated with the 5.31% 2018 Senior Unsecured Notes to arrive at a weighted cost of long-term debt for the rate effective period of 5.18%, a reduction from the current weighted cost of long-term debt of 5.34%. For short-term debt, the Company projects the cost of short-term borrowings based on the pricing of its existing revolving credit facility and a forecast of the London Inter-Bank Offer Rate (LIBOR). Staff finds the projections of the cost of the debt components to be reasonable.

H. Flotation Costs

The Commission has, in prior rate cases, permitted an upward adjustment to ROE to reflect the costs associated with the sale of new issues of common stock. To recognize the cost of issuing equity which were incurred by the proxy group companies in their most recent two issuances, in exhibit JP-9, Mr. Perkins calculates a Flotation Cost Adjustment based on an average weighted cost of issuance of 3.121%. The Flotation Cost Adjustment is 0.10%. Staff does not dispute a flotation cost adjustment but has updated these costs by adjusting the proxy group used in the calculation to make it consistent with the rest of Staff's analysis. The adjusted average cost of issuance is 2.933% and the floatation cost adjustment is 0.09%. It should be noted, however, that the average weighted cost for Emera Inc.'s last two common equity issues was 4.165%, putting its floatation costs squarely in the top quartile of all comparable issues within the proxy group.

I. Federal Tax Rate Reduction

On December 20, 2017, the Tax Cuts and Jobs Act was passed by both the U.S. Senate and the House of Representatives. It is expected to be signed into law early in January 2018. Among other provisions, this tax reform act reduces the federal corporate tax rate to 21% from 34%. For purposes of calculating the pre-tax WACC, Emera Maine's filing reflects the current federal income tax rate, which results in a pre-tax weighted average cost of equity of 7.86% and an overall WACC of 10.45%. Staff estimates that incorporating the new corporate tax rate into the WACC calculations would result in a reduction of the tax gross-up factor applicable to the equity component of the capital structure from 40.8% to somewhere in the range of 27.8%. With no other changes to the WACC requested by the Company, Staff estimates that this lower federal tax rate would result in a reduction in the pre-tax WACC to 9.03% and a reduction to the revenue requirement of approximately $4 million. In its rebuttal testimony, the Company should update its WACC calculations to reflect this change in the federal corporate tax rate.

J. Staff Recommended Weighted Average Cost of Capital

Combining the Staff recommended ROE of 9.00% with the Company's proposed capital structure and costs produces a pre-tax WACC of 10.04% as shown in Table 20. This pre-tax WACC does not include any adjustment for changes to the corporate tax rate.

Table 20

Staff Recommended Capital Structure, Costs and ROE

Emera Maine Bench Analysis					
Weighted Average Cost of Capital					
Capital Structure	Ave. Balances	Ratios	Rate	Cost	Pre-Tax WACC
					Tax Gross up 40.8045%
Long-Term Debt	287,694,662	47.03%	5.18%	2.44%	2.44%
Short-Term Debt	23,909,833	3.91%	3.96%	0.15%	0.15%
Preferred Stock	365,400	0.06%	7.00%	0.00%	0.00%
Common Stock	299,700,000	49.00%	9.00%	4.41%	7.45%
	611,669,895	100.00%		7.01%	
	Pre-Tax Weighted Average Cost of Capital				10.04%

VI. REVENUE REQUIREMENT

A. Rate Base Issues

1. CU-CIS Upgrade

The Staff recommends excluding this item from rate effective year revenue requirement per the discussion in Section IV(C) above.

2. Customer Experience Unspecified Spending Project

The Staff recommends excluding this item from rate effective year revenue requirements per the discussion in Section IV(E) above.

3. Power On and GIS Upgrades

The Staff recommends excluding this item from rate effective year revenue requirements per the discussion in Section IV(G) above.

4. Additions to Rate Base

In calculating its rate year rate base Emera Maine has added estimates for capital expenditures during 2017, 2018 and through June 2019 (Exhibit RR-23) impacting Electric Plant-In-Service, Accumulated Depreciation and Accumulated Deferred Income Taxes included in Rate Base. Commission Staff has concerns about the estimates for 2018 and 2019 capital additions.

a. 2018 Capital Additions

Emera has estimated capital additions of $34,516,075 for calendar year 2018. This is approximately an 18% increase over the additions estimated for 2017. In reviewing the response to ODR-001-032, Attachment A, Base Additions increase by approximately 4.4% while Major Additions increase by 217%. Staff believes that the increase in Base Additions should follow the inflation adjustments proposed elsewhere by Emera and should not increase more than 2.05%. Applying that inflation rate to the 2017 budgeted base additions would decrease 2018 Base Additions by approximately $691,209 before adjusting for the associated changes in depreciation of taxes.

Regarding the 2018 Major Additions not addressed elsewhere in this Bench Analysis, Commission Staff is not confident that Emera will actually put all of the projects into service during 2018 and could recommend that a portion of those projects be removed from Emera's rate base. In its Rebuttal Testimony, Emera should provide a status of each of these projects and support showing that it is likely that the projects will go into service as projected.

b. 2019 Capital Additions

The capital additions estimated for January through June 2019 are 50% of the total estimated additions for 2017 and are shown to be added to rate base ratably over the period January through June. Emera's response to ODR-001-033, Attachment 1, shows the monthly pattern of when capital additions are closed for rate base, and indicates that Emera's additions have not occurred ratably over each month and that in none of the completed years shown in that response were more than 37% of the total year's additions added to rate base during the first six months of the year.

While the total 2019 estimated additions have not been provided, Staff believes that Emera has assumed that 50% of the additions will occur during the first half of the year and has calculated its capital additions based upon this assumption. Given the fact that this is not historically accurate, Staff concludes that Emera has overstated the 2019 capital additions and therefore, has overstated rate base. Staff estimates that by using a 3-year average of when Emera's capital additions actually occurred during 2014 to 2016, the 2019 capital additions during January through June would be closer to $6,875,746 than the $14,684,706 estimated by the Company. This would reduce rate base by $7,808,960 before adjusting for the associated changes in depreciation and taxes.

5. Lower Main Street Property

Emera entered into a purchase and sale agreement for the sale of the Lower Main Street Property and expects this sale to close in Quarter 2 of 2018. (DT KC-30, line 20) Emera states that the pending sale will not result in a gain on the sale of the building and the Company has reflected the pending gain on the sale of the land to a below the line account (Account 421.1) in its rate filing consistent with FERC accounting rules. Emera allocated the net sales proceeds between the land and the depreciable assets using the tax assessed value. Emera estimates the gain on the sale of the land to be $249,923. (Exhibit RR-25) Emera retired the Lower Main Street Property and the original cost was offset against accumulated depreciation. Exhibit RR-25 indicates that Emera incurred $447,615 of removal costs related to the Lower Main Street facility. Consistent with normal utility accounting practice, Emera charged the full cost of removal against the accumulated depreciation balance.

While Emera's accounting of this transaction does reflect the requirements of the FERC Uniform System of Accounts, it results in the largest portion of the gain on the sale of these assets being retained by Emera rather than by the ratepayers. In addition, Emera's accounting will require its ratepayers to incur the full cost of removal. FERC accounting rules do not govern rate making. It is unlikely that the cost of removal is entirely related to the building given the purchase and sale agreement requires the completion of work on the land as well as the building. Therefore, the cost of removal should not be born entirely by ratepayers.

In the past, the Commission has used a risk/burden analysis laid out in

Democratic Central Committee v. Washington Metropolitan Transit District, 485 F.2d 786 (D.C. Cir. 1973), to determine how gains realized from utility investment should be distributed. Where ratepayers bear the risk of loss or shoulder burdens associated with utility investments, the Commission has found that ratepayers are entitled to the gain on the investment. *Central Maine Power Company, Annual Price Change Pursuant to the Alternative Rate Plan*, Docket No. 99-00155, Order on CMP's Motion for Reconsideration (Jan. 20, 2000).

In this instance, the ratepayers assumed the depreciation costs associated with the Lower Main Street property, and bore the risk of sale at a loss. Although for property tax purposes the land and buildings maybe separable, ratepayers have also provided investors with a return on the total investment throughout the period that the property was owned by Emera and maintained that investment. As the Commission has noted previously, since investors are not entitled to a return on the fair value of rate base, they "do not possess a vested right in value-appreciations accruing to in-service assets." *Democratic Central* at 804; *Central Maine Power Company, Annual Price Change Pursuant to the Alternative Rate Plan*, Docket No. 99-00155, Order on CMP's Motion for Reconsideration at 10-11 (Jan. 20, 2000). Therefore, for ratemaking purposes Staff recommends that the $249,923 gain that Emera has attributed to sales should be used to reduce the removal costs associated with the retirement and sale of the Lower Main Street property.

6. <u>Acadia Substation Investment</u>

The Company has made a $6,695,061 adjustment to test year electric plant as well as related depreciation and ADIT adjustments related to its Acadia Substation. The

Company has reflected its full costs in this base rate case, but acknowledges that this amount is under investigation by the Commission in Docket No. 2017-00018. As noted by the Company, the investigation is scheduled to be completed prior to the conclusion of this rate case. Emera will be expected to update its revenue requirement as applicable following the final Order in Docket No. 2017-00018.

7. PERC/Working Capital Allowance

In an adjustment to rate base the Company calculates a cash working capital allowance which includes the working capital requirement associated with Purchase Power Expense and Off-system Sales. The Company's proposal does not include any adjustment to recognize that the contract with Penobscot Energy Recovery Company (PERC) terminates at the end of February 2018. When asked at the December 1 technical conference about the effect on the working capital allowance of the termination of the PERC contract, Mr. Chahley indicated that there could be an adjustment to the working capital allowance to reflect the PERC contract termination, any new contracts and any changes in actual and forecasted contract volumes. Tr. 106-107, lines 22-25.

Staff has adjusted the working capital requirement to remove the effect of the PERC contract. To make the adjustment, Staff removed any revenue or expense associated with the PERC contract from the Purchase Power and Off-system Sales calculations in the lead-lag detail provided in response to EXM-005-047. The resulting revenue and expense amounts were then carried over to the Rate Base Adjustment # 18 in the Company's revenue requirements. The removal of the revenues and expenses associated with PERC has the effect of reducing the working capital allowance calculated by the Company by $1,068,164, from $3,385,365 to $2,317,201. The Staff did not make any additional adjustments to reflect any new contracts or changes to the price or forecasted quantities to be delivered under any power purchase agreements. To the extent there are additional known and measurable changes to reflect changes to the Purchase Power and Off-system Sales calculations, the Company should provide those in its rebuttal testimony.

B. Cost of Service Issues

1. Costs Associated with Inspection Catchup

The Company's test year expense includes $70,430 for costs associated with the inspection catchup program. Since the Commission included costs associated with the Company's inspection program when it set rates in Docket No. 2013-00443 and since in Docket No. 2015-00360, the Commission found that the Company's suspension of its inspection program in 2014 and 2015 was not a sound management practice. Staff believes that ratepayers in this case should not be forced to bear the costs associated with the inspection make-up. As a result, Staff recommends the exclusion of such costs from revenue requirements in this case.

2. Vegetation Management Costs

The Company has proposed a $2,068,331 adjustment to reflect its new five-year cycle trim costs. At this point, the costs of the program are not sufficiently definite to constitute a known and measurable change. The adjustment should be updated once a vendor is retained. To the extent that this does not occur by the conclusion of the case, the Staff recommends that the amount included in rates in this case be updated as part of the proposed follow-on rate plan proceeding.

In addition, the Staff would note that in its updated filing of December 12, 2017, the Company increased the amount for this expense by adding $55,340 for test-year internal labor costs. To the extent that test year vegetation management costs are increased for internal labor, Staff believes that a corresponding reduction to the overall labor expense should be made.

3. Customer Late Payment Resources

The Company has proposed to include $677,868 for customer late payment revenues in the rate year based on 2016 revenue of $600,520. The 2017 year to date annualized revenue amount for this item is $693,227. This results in an annual change rate of 15.44%. Applying this rate to 2017 amount results in a rate effective year amount of $862,016, or an increase of $184,148 to the adjustment proposed by the Company.

4. Storm Costs

The Company's test-year amount for non-extraordinary storm costs was $3,734,037. Using a four-year average (2014-2017) the Company calculates a normalized non-extraordinary storm costs of $2,032,929 which results in a reduction to test year expense of $1,701,118. The Company states that its use of a four-year average is consistent with the Commission's methodology in Docket No. 2015-00360.

In Docket No. 2015-00360, the Commission noted that it preferred to use a five-year normalization for storm costs. However, since 2012 costs were almost 20% less than the next lowest cost year, the Commission considered 2012 to be an outlier and dropped 2012 from the analysis As a result, the Commission used a four-year average. In this case, 2016 is approximately 50% greater than the next highest year in the data set and, thus, can also be considered an outlier. Applying the four-year outlier methodology results in a four-year normalized level of $1,410,750. This count should be updated later in the case for complete 2017 results. If a straight five-year normalization is used, the normalized amount would be $1,875,624. Depending on the methodology used, the reduction to test year expense should be increased by either $622,174 (4 year) or $157,305 (5 year).

5. <u>Medical and Other Employee Related Insurance Costs</u>

This category of expenses includes medical claims, admin/other medical insurance, employee contributions and other insurances. The admin/other medical insurance line or the category went from $576,878 in 2014 to $533,294 in 2015 and then up to $693,437 in 2016. The Company used the sole test year amount and then projected this amount forwarded by the rate of inflation to arrive at a $729,225 rate year amount.

In response to EXM-005-032, the Company has reported that the year to date amount for admin/other medical insurance to be $564,630. It would appear that 2016 is an outlier and should not be used as the basis for projecting rate year expense for this item. Using the 2017 year to date actual amount and trending this amount forward by the Company's inflation rates results in a rate year Company amount of $582,540 of which $510,946 would be allocated to distribution. This reduction in expense reduces revenue requirement by $125,131.

6. <u>Bonus Compensation</u>

The Company's compensation plan includes a Balanced Scorecard (BSC) Incentive Plan. Employees are eligible for bonus compensation when the Company meets or exceeds certain goals related to safety performance, workplace excellence, customer service, asset management and financial performance.[34] As explained at the December 1, 2017 technical conference, the actual BSC payout amount an employee receives is determined by Company performance, the employee's classification and base salary, and their individual performance.[35]

The BSC explains that the financial performance goals are aimed at measuring the effectiveness of Emera meeting its earnings targets and managing its operating cash flows. OPA-002-026 Attachments A and B. In 2016 the Company paid $515,995 under the BSC incentive plan related to financial performance. Company executives were paid $91,912 and managers were paid $79,022 of that amount. ODR-001-043 Attachment A.

[34] OPA-002-026 Attachment B

[35] Tr. 109-114

Given Staff's concerns related to the Company's performance discussed throughout this Bench Analysis, we do not believe it is appropriate to include executive and management bonus compensation for financial performance in revenue requirements to be recovered from ratepayers. Therefore, Staff recommends a reduction in revenue requirements of $149,929 ($170,934 less 12.29% allocated to transmission).

7. <u>Non-Labor Regulatory Expenses</u>

The Company has included $300,000 as an adjustment to non-labor regulatory expenses for a rate design study. (Exhibit RR-71) At the December 1, 2017 technical conference, Mr. Chahley explained that the intent would be to "piggyback" on cost of service study work already completed and that the incremental $300,000 would be for consultants to assist in designing the rates. Tr. at 93-94. Staff is not confident that this work will be completed during the rate effective year. When asked at the November 30, 2017 technical conference whether the Company was considering filing a rate design case in the future, Mr. Richardson explained:

> Contemplating, yes…our focus is before we turn our minds to rate designs and other things, we have to get the core business on solid footing… I can't give you a specific time that it'll take six months, it'll take 12 months, but – but we want to get the – the core business running well…Its kind of next up, but – but we didn't want to take our eye off the ball in any way about the core business because we feel like that's – we have to get that right first.

Tr. 21-22.

From this response, it appears that although the Company may have a desire to conduct a rate design study in the future, it has no concrete plan to do so during the rate effective year. In addition, the Company has provided no basis for the estimated cost amount. Staff takes the position that this is not a known and measurable amount and therefore the $300,000 amount should be excluded. In addition, this cost is repetitive as Emera as part of a stipulation in Docket No. 2014-00172, conducted cost of service studies which is a core component of a rate design study.

In addition, if it is determined that it is appropriate to include this amount as an adjustment to expenses, Staff believes that the amount should not be included in full. Instead, similar to how rate case costs are treated, the costs should be normalized over the period these studies would normally occur. The Company explained that because it does not regularly conduct rate design studies it is appropriate to include the cost as a lump-sum rather than normalize the cost. Tr. at 94-97 (December 1, 2017). Staff rejects this explanation. By including the full amount in revenue requirements, the Company would receive that amount of revenue each and every year those rates are in effect, which in total would result in the Company receiving multiple times the actual cost of this study. Normalization of the cost over a given period is designed to allow the Company to include in rates the normal annual cost of ongoing regulatory activities. With regards to the cost of service studies done pursuant to Docket No. 2014-00172, Emera has proposed to normalize these costs over a five-year period. Emera has indicated that it selected the same normalization period as used for rate case proceedings. Staff disagrees that these studies occur at the same interval as rate case proceedings do. Therefore, Staff proposes that the normalization period should be 10-years instead of five. The impact of these two proposed adjustments is a $349,299 reduction to revenue requirements.

8. Impact of Tax Reduction

As noted earlier, as of the date of this Bench Analysis, the Tax Cuts and Jobs Act has been passed by Congress and is expected to be signed by the President. Among other provisions, this tax reform act reduces the federal corporate tax rate to 21% from 34%. Emera's accumulated deferred income taxes reflect the higher tax rate of 34% and because of the reduction in the tax rate now include excess deferred income taxes. Commission Staff notes that a similar situation existed after the implementation of the 1986 Tax Reform Act. In that case, the Average Rate Assumption Method (ARAM) was developed that required the return of the excess deferred income taxes over a period no faster than what would have happened if the tax rate had not changed, essentially returning the deferred income taxes over the remaining life of the assets that had created them. Staff notes that it expects all excess deferred income taxes to be returned to ratepayers over a period no longer than would have happened if there was no tax change.

Staff also notes that throughout its rate filing Emera reflects the impact of the tax rate on assets moving forward and would expect Emera to update its filing in its Rebuttal Testimony to reflect the tax rate change. To the extent that Emera believes that there are other aspects of the Tax Cuts and Jobs Act that impact the Company and its proposed rates, it should specifically document the sections of the law and quantify the impact on rates in its Rebuttal Testimony.

VII. OVERALL MANAGEMENT EFFICIENCY ASSESSMENT

Although Emera Maine has reported improvements in certain performance metrics, Commission Staff continues to be concerned about the Company's overall management efficiency. Staff has observed a series of issues which may suggest a more systemic problem with the management and culture of the Company. Taken individually, each instance might not support a conclusion that management issues continue to plague Emera Maine. Collectively, however, these problems tend to show a company that is not well managed or operating efficiently. Some of these issues are related to Commission cases and actions and the noted Emera Maine short-comings also suggest an on-going weakness in the support Emera Maine provides to Commission activities. Specifically, these issues include:

- In November 2016, the Commission accepted a standard offer bid for service in the Maine Public District (MPD) that was contingent upon a change to NMISA's Market Rule 10 and approval of the change by FERC. The bid was structured to provide service to MPD customers at a discount to the standard offer prices set for service areas within ISO-NE. When the market rule change came up for a vote of the NMISA Board Members, Emera Maine voted against the proposed change, even though failing to pass the measure would lead to higher supply prices for MPD customers. The rule change passed without Emera Maine's support. At FERC, the Commission, OPA and a group of Maine customers supported the rule change. Emera Maine did not file comments.

- Pursuant to an Act To Establish a Process for the Procurement of Biomass Resources (Act) P.L 2015, ch. 483, the Commission has authorized two contracts with biomass generators and a Cost Recovery Fund (Fund) has been created at the Commission to pay all above-market costs of the contracts. To accurately administer the Fund, Emera Maine is required to submit monthly reports tracking the output and wholesale pricing of the generation from one of the generators on a monthly basis. The Company has consistently failed to timely submit the required information. As of the date of this Bench Analysis, Commission Staff has had to request the information from Emera for five of the nine months. In addition, Staff has identified errors in four of the nine reports requiring the Company to recalculate and resubmit the information.

- Over the past two years, there have been several billing issues that Emera Maine seemed to be unable to resolve in a timely fashion without the active intervention of the director of the Commission's Consumer Assistance and Safety Division (CASD).

- In one instance, a meter serving a large commercial customer began registering zero in July 2016. The CASD received notification in October 2016 from the competitive electricity provider (CEP) serving the customer that that it was not receiving payment from Emera Maine and had been unable to resolve the issue despite numerous calls to the Company. After discussions with the Company, the director of CASD determined that the Company had failed to resolve the problem at several points: first, in August when it became aware the meter was reading zero and issued an order to replace it; second, in September when the CEP contacted the Company about nonpayment; and finally, in October when the CASD became involved. The meter was replaced at the end of October.
- The second incident stems from repeated billing errors involving a medium commercial customer. The customer notified Emera Maine in August 2016 of an expected change in the estimated usage by an unmetered lighting fixture but did not make the appropriate change in its billing system to allow for a correct bill to be issued before the September bill was sent. The September bill was subsequently cancelled and re-billed, also incorrectly. The October bill was also incorrectly issued, cancelled and rebilled. From discussions between the director of CASD and the Company, it appears that nothing had been done to correct this billing error until the end of October when the CASD became involved.

- In a recent workshop session to resolve engineering and technical issues related to the net energy billing rule, the participants from CMP included interconnection and billing system experts, the manager of energy supply and utility senior management. Emera Maine's sole participant was a staff attorney.

- Emera Maine is the contract counter-party to a contract with Ocean Renewable Power Company (ORPC), a power purchase agreement authorized by the Commission in 2012. Energy deliveries under the ORPC contract began in 2013. The agreement requires Emera Maine to track energy deliveries, above-market costs and the funds available to support the above-market costs and to report the status to the Commission annually. Emera Maine has not yet filed an annual report.

- The Commission's standard offer supply solicitations require the active involvement of the T&D utilities, both in providing required load data, reviewing and negotiating service agreements with bidders, conducting a request for bids for the sale of entitlements, and executing agreements with the bidders selected by the Commission. This process is often conducted under time constraints, particularly on the final bid day. On that day, final bids are submitted and analyzed, the Commission selects the winning bids and the documentation must be executed, all within the span of several hours. Over the past several standard offer solicitation cycles, Staff has found Emera Maine's support of the standard offer process to be lacking, particularly with respect to compliance with the requirements for providing data, submission of correct and complete entitlement bid documents, and availability for discussing and executing agreements.

In light of these management issues and the continuing management issues discussed in Section III and Section IV above, the Staff recommends that the Commission continue to apply an ROE that is at the lower end of the reasonable range of results. Based on Staff's ROE analysis, the Staff recommends that an ROE of 8.75% is appropriate here given the continuing management efficiency issues present at the Company.

VIII. RATE PLAN

After a series of base rate cases filed by Central Maine Power (CMP), the last of which involved a management audit and a management efficiency cost disallowance, the Commission concluded that an alternative rate making approach (price cap or rate stability plan) should be adopted for CMP. *Central Maine Power Company, Proposed Increase in Rates*, Docket No. 1992-00345, Order at 130 (Dec. 14, 1993). The Commission concluded that a multi-year price cap plan was likely to provide a number of potential benefits including:

- Electricity prices continue to be regulated in a comprehensible and predictable way.
- Rate predictability and stability are more likely.
- Regulators "administration" costs can be reduced allowing the utility to expend more time and resources in managing its operations.
- Risks can be shifted to shareholders and away from ratepayers.
- Exceptional cost management can lead to enhanced profitability for shareholders, thus, creating strong incentives for cost minimization.

Id.

The Commission emphasized that a key benefit of price caps is the strong incentive to be cost effective. The Commission recognized, however, that price cap regulation was not a panacea and that the price cap structure may lead to a lower quality or reliability of service, excessively high or low profits, discriminatory prices, and the risk that consumers will see little benefit from actual productivity improvements. The Commission, nonetheless, concluded that:

> The potential benefits outweigh the potential costs and work to implement a rate stability plan in the near future. The primary factor driving us to this conclusion is the same theme we have expressed throughout this Order, namely that CMP has not operated as efficiently as possible and we want to implement a system whereby CMP will benefit if it is efficient and will suffer if it is not.

Id. at 131.

Given the series of rate cases submitted by the Company since 2013 and the management efficiency issues which have been raised in Docket No. 2015-00360 and in this proceeding, the Staff believes that it is appropriate to initiate a rate stability plan proceeding at the conclusion of this case much like the Commission did in Docket No. 1992-00345.

The Company in this case has stated that it is not in a position to propose a multi-year rate plan at the present time. Specifically, the Company notes the following four areas where it needs to advance its thinking:

1. It wants to be sure that the metrics and targets it uses to define and measure successful service to customers represents the best thinking for today and for the future, versus the past.
2. It wants to be sure that the Company has a solid understanding of what it will take for Emera Maine to meet its customers' current and future expectations, in terms of people, process and technology. On the technology side, in particular, Emera Maine wants to be sure that its plan for the period covered by a multi-year rate plan is solid and is aligned with the expectations of customers, stakeholders and the Commission.
3. It wants to do what it can to support economic growth in its territory and in Maine, and believes that improved rate designs could help.
4. The Company's business model is subject of a number of potential

> challenges, including but not limited to challenges which lower sales volume, which today is the billing determinant for most of our revenues. If Emera Maine were to propose a multi-year plan, it would need some confidence that sales volumes could be expected to support the revenue requirement or alternatively, propose some form of de-coupling. This is not something the Company has studied in any detail at this point.

When asked when the Company believed that its thinking would advance to the point that it would be in a position to file a rate plan proposal, Emera Maine President Alan Richardson responded that the Company did not have an estimate for either the advancement of its thinking or the timing for filing a rate plan proposal. EXM 001-007.

The Staff does not believe that any of the reasons put forward by the Company preclude the consideration, or the ultimate adoption of an alternative rate plan. The metric to be applied during the rate plan, the design of a revenue developing mechanism and the outcomes from a possible future rate design case, could all be considered as part of the rate plan proceeding. With regards to the technology issue, the Staff would note that since the Commission initially considered the issue of whether to utilize alternative ratemaking, technology has been rapidly advancing and will continue to advance. This does not mean, however, that the implementation of an appropriate ratemaking paradigm designed to incent efficient behavior should not be considered. The Staff respectfully recommends, therefore, that the Commission initiate a Phase II proceeding at the conclusion of this rate proceeding to consider rate plan proposals for Emera Maine which would take effect on July 1, 2019.

December 21, 2017 Respectfully submitted,

Charles Cohen
Hearing Examiner

Jordan McColman
Hearing Examiner

On Behalf of Advisory Staff:

Faith Huntington
Derek Davidson
Christine Cook
Lucretia Smith
Sally Merritt
Matthew Rolnick

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2017-00065

October 6, 2017

NORTHERN UTILITIES, INC. d/b/a UNITIL
Request for Approval of a Rate Change
Pursuant to Section 307

BENCH ANALYSIS

I. INTRODUCTION

On May 31, 2017, Northern Utilities, Inc. d/b/a Unitil (Northern or the Company) submitted its Chapter 120 information and Direct Testimony in this matter. By way of this filing, Northern requested authorization to raise its distribution revenues by $5,981,413 or 12%. As part of its filing, Northern requested that the Commission extend the Company's Targeted Infrastructure Replacement Adjustment (TIRA) mechanism which provides for capital cost recovery of the investments associated with the Company's Cast Iron Replacement Program (CIRP), Unprotected Steel Replacement Program (UPS) and Farm Tap Replacement Program. The Company's revenue requirement deficiency was based on a Return on Equity (ROE) of 10.30%. The Company submitted Supplemental Testimony on August 18, 2017 which proposed an additional increase in rates of $667,000 related to the Saco Targeted Area Buildout (TAB) investment.

On August 31, 2017, the Office of the Public Advocate (OPA) filed its direct case in response to the Company's rate increase proposal. In its case, the OPA recommends that the Company's initial increase request be reduced to $822,354. The OPA also recommended that the Company's Saco TAB increase be reduced to $464,139. The OPA's proposal relied on a ROE of 9.15%.

The Staff files its Bench Analysis in response to the Company's filing and raises issues which were not previously raised in the OPA's filing, or were raised by the OPA but where the Staff's proposal differs in some aspects from the OPA's proposal. The analysis presented here represents Staff's views on these issues based on the information presented to date. In certain instances, the proposals or analysis will need to be updated based on data which will be presented later in the case. The Staff's final recommendations to the Commission will be contained in the Examiner's Report scheduled to be issued on February 6, 2018.

II. BASE REVENUE REQUIREMENT ISSUES

A. Rate Base

1. Gain on Sale of Property

In response to EXM-004-031, Northern stated that in 2015 it sold property at Forest Avenue in Portland. Northern received $1,374,285 in proceeds for this property, which had an original cost of $408,338, made up of $95,095 for land and $313,243 for the building. Northern also incurred a cost of removal of $43,838. This resulted in a gain of $922,110. Northern recorded this gain in Account 421.1, Gain on Disposition of Property. ODR-003-024. While the accounting of this transaction does reflect the requirements of the FERC Uniform System of Accounts, it results in the gain on the sale of these assets being retained by Northern rather than by the ratepayers.

In his Direct Testimony on behalf of the OPA, Lafayette K. Morgan, Jr. disagreed with Northern's treatment of the gain and proposed an adjustment to reflect a 3-year amortization of the gain on the property to flow back the gain to ratepayers. At the September 19, 2017, technical conference, Mr. Morgan indicated that he would not object to an amortization period of 4-years to be consistent with the estimated period between rate proceedings.

In the past, the Commission has used a risk/burden analysis laid out in *Democratic Central Committee v. Washington Metropolitan Transit District*, 485 F.2d

786 (D.C. Cir. 1973), to determine how gains realized from utility investment should be distributed. Where ratepayers bear the risk of loss or shoulder burdens associated with utility investments, the Commission has found that ratepayers are entitled to the gain on the investment. *Central Maine Power Company, Annual Price Change Pursuant to the Alternative Rate Plan*, Docket No. 99-00155, Order on CMP's Motion for Reconsideration (Jan. 20, 2000).

In this instance, the ratepayers assumed the depreciation costs associated with the Forest Avenue property, and bore the risk of sale at a loss. Ratepayers have also provided investors with a return on investment throughout the period that the property was owned by Northern. As the Commission has noted previously, since investors are not entitled to a return on the fair value of rate base, they "do not possess a vested right in value-appreciations accruing to in-service assets." *Democratic Central* at 804; *Central Maine Power Company, Annual Price Change Pursuant to the Alternative Rate Plan*, Docket No. 99-00155, Order on CMP's Motion for Reconsideration at 10-11 (Jan. 20, 2000). Therefore, Staff agrees with the OPA that the proceeds of the sale of the Forest Avenue property should be flowed back to ratepayers, and recommends a 4-year period.

Because of the recommended four-year flow-back, Northern should create a regulatory liability with an appropriate debit for deferred income taxes which together should be used an adjustment to rate base. Specifically, a regulatory liability of $922,110 should be recorded in Account 254, Other Regulatory Liabilities, to be amortized over a four-year period to Account 407.3, Regulatory Debits. A deferred tax debit of $367,830 should also be recorded. ($922,110 x 39.89% Statutory Tax Rate). This results in a rate base reduction of $554,280.

2. Incentive Compensation

As discussed in more detail in Section II.D.3, the Staff has determined that only a portion of the incentive compensation costs incurred should be recoverable from ratepayers. Northern, as part of its overhead accounting process, capitalized 50.29% and 30.90% of the Northern and USC incentive compensation in 2016. Therefore, rate base should be reduced by $357,035 to reflect the Staff position that these incentive costs are not recoverable.

3. Working Capital Adjustment

Similar to the bad debt expense adjustment discussed later in this section, adjustments proposed in the Bench Analysis that change the level of costs included in the working capital calculation would result in changes to the working capital to be included in rate base. This change will result in a change in the return on rate base included in the revenue requirements used to calculate the rates.

B. Cost of Capital

1. Northern Testimony

Northern's cost of equity witness, Robert Hevert, develops a current cost of equity in the range of 10.00% to 10.60% and recommends a return on equity (ROE) of 10.30%. In developing his recommendation, he first identifies a peer group of utilities and then employs several methodologies to estimate Emera's ROE, including the Discounted Cash Flow (DCF) model (using a Constant Growth and Multi-Stage form), the Capital Asset Pricing Model (CAPM) and the Bond Yield Plus Risk Premium approach.

The Company computes its weighted average cost of capital (WACC) using a common equity ratio of 51.7% and long-term debt equal to 48.3% of total capital at a cost of 6.16%. Mr. Hevert states that Northern's proposed capital structure is generally consistent with the capital structure of the proxy group companies, which, over the last eight quarters, had a mean common equity ratio of 49.74% and long-term debt ratio of 50.26%. Northern does not include a short-term debt component in its capital structure but does provide a recent short-term debt cost of 2.19%. Northern's proposed capital structure, costs and ROE result in a pre-tax weighted average cost of capital (WACC) of 11.83% and an after-tax WACC of 8.30%.

Figure II.1

Northern as Filed					
Weighted Average Cost of Capital					
Capital Structure	**Amount**	**Ratios**	**Rate**	**Cost**	**Pre-Tax WACC**
					Tax Gross up 39.89%
Long-Term Debt	$ 145,000,000	48.30%	6.16%	2.98%	2.98%
Short-Term Debt	$ -	0.00%	2.19%	0.00%	0.00%
Preferred Stock	$ -	0.00%	0.00%	0.00%	0.00%
Common Stock	$ 155,183,729	51.70%	10.30%	5.33%	8.86%
	$ 300,183,729	100.00%		8.30%	
Pre-Tax Weighted Average Cost of Capital					**11.83%**

Northern Capital Structure, Costs and ROE

2. <u>OPA Testimony</u>

The Public Advocate's consultant, Lafayette Morgan, bases his recommended ROE on the Company's testimony and analysis. Mr. Morgan considers the results of the DCF analysis using only the mean growth rate results developed by Mr. Hevert and eliminates the mean-low and mean-high growth rates. Based on this analysis, Mr. Morgan recommends an ROE of 9.15%, the average of the DCF results produced by the Company.

The OPA also recommends changes to the level and cost of long-term debt and a modification to the Company's capital structure. Specifically, the OPA revises the outstanding debt balance to reflect the retirement of $10 million in 6.95% debt in December 2017 and the issuance of $50 million in new long-term debt at a weighted average cost of 4.00% in November 2017. These changes result in a pre-tax WACC of 9.97% as shown in Figure II.2 below.

Figure II.2

OPA Testimony					
Weighted Average Cost of Capital					
Capital Structure	**Amount**	**Ratios**	**Rate**	**Cost**	**Pre-Tax WACC**
					Tax Gross up 39.89%
Long-Term Debt	$ 185,000,000	54.38%	5.55%	3.02%	3.02%
Short-Term Debt	$ -	0.00%	2.19%	0.00%	0.00%
Preferred Stock	$ -	0.00%	0.00%	0.00%	0.00%
Common Stock	$ 155,183,729	45.62%	9.15%	4.18%	6.95%
	$ 340,183,729	100.00%		7.20%	
Pre-Tax Weighted Average Cost of Capital					**9.97%**

OPA Testimony Capital Structure, Costs and ROE

3. Hope-Bluefield Standard

Underlying the question of an appropriate return on equity for any regulated utility are two United States Supreme Court decisions of more than 70 years ago, known as the *Bluefield* and *Hope* cases, which provide the standards for measuring the reasonableness of a utility's allowed ROE. Taken together, the *Hope-Bluefield* decisions establish that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made…on investments in other business undertakings which are attended by corresponding risks and uncertainties…The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to

> maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties...

Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

Additionally, the idea of associating the allowed return to a common equity owner with those available from other companies of comparable risk was established in the *Hope* decision:

> [T]he return to the equity owner should be commensurate with the return on investment in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

Thus, the practice of determining an appropriate ROE for a company that is not publicly traded such as Northern is one that involves developing a comparable group of companies, for which market-based information is available, that are in the same business and that present similar financial risks.

4. <u>Proxy Group Selection</u>

As with any analysis of the appropriate ROE for a regulated utility, the starting point is the selection of a comparable group of companies and the development and application of screening criteria to the applicable group to select a proxy group. Mr. Hevert began with a group of 45 domestic utilities classified by Value Line as ”Electric Utilities” and “Natural Gas Utilities” and excluded companies based on certain screening criteria.

Staff does not take issue with most of the criteria and application of the criteria by Mr. Hevert. The selection of proxy members based on publicly traded companies that pay dividends is essential to a discounted cash flow (DCF) analysis. In addition, companies that are covered by more than one analyst and have an investment grade credit rating provide reasonable assurance that the market-based analysis that underlies a return on equity determination reflects market information.

Eliminating companies that have been a party to a recent merger transaction helps ensure that the ROE range determined based on the proxy group is not unduly influenced by significant events that affect an individual member of the group and is consistent with the criteria previously employed by the Commission in selecting an appropriate proxy group. In conducting its analysis Staff returned to the proxy group two companies which had been screened out: Dominion Resources and Duke Energy. Dominion Resources completed its merger with Questar in September 2016, and Duke Energy completed its acquisition of Piedmont Gas in October 2016.

Additionally, Staff agrees with Mr. Hevert's decision to include only companies with at least 30% of operating income derived from regulated natural gas utility operations. Staff would have preferred a higher level of operating income from regulated natural gas utility operations, but raising the operating income requirement would have narrowed the proxy group to an unacceptably small sample. As Staff has observed in prior electric utility rate cases, the risk profile presented by a gas LDC is similar to the risk profile presented by a transmission and distribution only electric utility.[1] Thus, it may be useful to examine expanding the gas proxy group to include more companies that may be electric utilities but are primarily transmission and distribution (T&D) operations.

Staff began with SNL's universe of Electric and Gas companies and screened that list to exclude companies with regulated revenues as a percentage of total operating revenues of less than 30%. Staff then examined the jurisdictions in which the

[1] *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket No. 2015-00360, Bench Analysis at 6 (June 2, 2016).

electric utilities operate to ensure that they operate primarily in restructured markets and thus, are T&D only utilities. Staff added three companies to the proxy group developed by Mr. Hevert which meet his original criteria plus these additional criteria: Consolidated Edison; Eversource Energy; and Public Service Enterprise Group Incorporated. Consolidated Edison has 77% of its revenue from regulated revenues and its operations are primarily in restructured markets and therefore do not have generation risk priced in. Eversource Energy was not in the original Value Line universe of utilities considered by Mr. Hevert, however, with 92% of its revenue coming from regulated utilities in the restructured markets of New England, Staff considers them to be an appropriate proxy. Public Service Enterprise Group reported 67% of its total revenue as regulated revenue. Its regulated operations are only in New Jersey.

We did not exclude any of the companies that Mr. Hevert had in his original screen. Finally, it should be recognized that substantially all members of the proxy group own some amount of regulated or unregulated electric generation. Although it is virtually impossible to quantify the additional risk factors presented by generation, those utilities retain the construction and operational risk associated with generating assets unlike LDC utilities that are primarily transmission and distribution in nature. Staff does not recommend a specific screen to the proxy group to eliminate companies with generating assets, as any appropriate screen would effectively reduce the proxy group to a size that would be not useful, but Staff does note the fact that the proxy group generally faces a set of business risks that Northern does not.

As a result of the above adjustments, Staff's final proxy group is as follows:

FIGURE II.3

HEVERT Proxy Group	STAFF Proxy Group
Company	Company
Atmos Energy Corporation	Atmos Energy Corporation
Black Hills Corporation	Black Hills Corporation
CenterPoint Energy, Inc.	CenterPoint Energy, Inc.
Chesapeake Utilities Corporation	Chesapeake Utilities Corporation
	Consolidated Edison, Inc.
	Dominion Resources
	Duke Energy Corporation
	Eversource Energy
Northwest Natural Gas Company	Northwest Natural Gas Company
	Public Service Enterprise Group Inc.
Sempra Energy	Spire Inc
Southwest Gas Corporation	Sempra Energy
Spire Inc	Southwest Gas Corporation
Vectren Corporation	Vectren Corporation

Staff Final Proxy Group

5. Constant Growth DCF Model for Estimating Cost of Equity

Consistent with past Commission practice and orders,[2] the Staff (and Mr. Hevert) employ a discounted cash flow (DCF) approach to the cost of equity analysis. The DCF model is commonly used for estimating the cost of common equity for public utilities and is based on the financial theory that the value or price of any security is the discounted present value of all future cash flows. As explained in materials published by the Society of Utility and Regulatory Financial Analysts[3]

> The DCF model is based upon two fundamental principles. First, DCF is based on the postulate that investors value an asset on the basis of the future cash flows (i.e., dividends and ultimate sales in the case of common stocks) they expect to receive from owning the asset. The second DCF principle is that investors value a dollar received in the future less than a dollar received today (i.e., the "time value of money"). Within this context, the current price of a company's stock is equal to the present value equivalent of the expected dividends and the proceeds from eventually selling the stock. The discount rate that equates the future anticipated dividends and the future anticipated selling

[2] *See. Central Maine Power Company, Proposed Increase In Rates*, Docket No. 92-345, Order at 31 (Dec. 14, 1993).

[3] Parcell, David C. The Cost of Capital—A Practitioner's Guide, Society of Utility and Regulatory Financial Analysts, 2010 Edition.

price with the current market price is the cost of common equity.

In its very simplest form, a DCF estimate of the cost of equity capital uses the formula

$$K=D/P + g$$

where:	K =	cost of equity capital
	D/P =	dividend yield (dividend payout/stock price)
	g =	long-term expected growth rate

In addition to this constant growth DCF model, other formulations of the DCF model that assume different growth rates over future time periods (multi-stage growth) can be used. Generally, the market based data (market prices and current dividends) required to conduct any DCF analysis are readily available.

A key component of the DCF formulation is the long-term expected future growth rate. A common method of estimating future growth is to use growth rates in earnings per share projected by securities analysts who follow the stock of the proxy group companies. In his constant growth DCF analysis, Mr. Hevert derives a range of indicated ROE by using growth rates equal to the maximum, the mean and the minimum of long-term earnings growth rates projected by securities analysts. In addition, as an alternative to using the analysts' growth rates, he derives an additional growth rate using a retention rate model based on the premise that a firm's growth is a function of its expected earnings and the extent to which those earnings are retained to invest in the enterprise. The growth rates used in Mr. Hevert's single stage growth DCF analysis range from 2.73% to 14.38% for individual companies and are used as a basis for establishing the high end and the low end of the ROE range.

In conducting its constant growth DCF analysis, for the long-term expected growth component of the formula (g), Staff used three different long-term expected growth rates in an effort to derive a range of indicated ROE: the average of the analysts' growth rates as reported on YahooFinance! on September 25, 2017 (5.21%); the average growth rate used by Mr. Hevert which included the retention growth rate (6.40%); and the average of the analysts' growth rates used by Mr. Hevert which excludes the retention growth rate (6.34%).

6. Staff DCF Analysis-Constant Growth Model

The actual DCF calculations as provided in B. A. Exhibit 1 are largely self-explanatory. To summarize, the current quarterly dividend for each utility as of September 25, 2017, was converted to a "forward" dividend. Many different models for the calculation of the dividend yield have been developed to account for the fact that companies declare, pay and may increase dividends at different times throughout the year. In past analyses, this Commission has preferred a model that assumes that future dividend increases will be evenly distributed over calendar quarters. The model assumes that the companies pay dividends quarterly but those dividends are changed only annually by the company in the middle of the year. Thus, the forward dividend reflects two quarters at the current dividend rate and two quarters at a higher dividend rate, increased by the assumed growth rate. To calculate the future dividend, Staff used the five-year analysts' growth estimates as reported by Yahoo! Finance on September 25, 2017. Staff calculated the dividend yield component of the model by dividing the resulting forward dividend by the share price for each utility.

In recognition of the day-to-day variability in closing share prices, we employed the closing market price for each of the proxy group companies as well as both a 50-day moving average of closing share price and a 200-day moving average of closing share price for each utility as reported by Yahoo! Finance on September 25, 2017. This resulted in a range of current dividend yield calculations for the entire proxy group, from a low of 1.70% to a high of 4.37%, averaging 3.08%. Staff then added the growth rates as discussed earlier to the low, mean and high calculated dividend yields to achieve an indicated range of estimates of ROE.

As shown in Figure II.4 below, the constant growth DCF model produces an indicated ROE range of 8.24% to 9.54%.

Figure II.4

Constant Growth DCF Indicated ROE	Growth Rate	Indicated ROE Range Low	Mean	High
Average Analyst Growth (YahooFinance)	5.21%	8.24%	8.28%	8.35%
Hevert (3 Analyst average)	6.34%	9.37%	9.42%	9.48%
Hevert w/ retention growth rate	6.40%	9.43%	9.48%	9.54%
	Min	Max	Mid	
Range:	8.24%	9.54%	8.89%	

Constant Growth DCF Model Indicated ROE

7. DCF Analysis-Multi Stage Growth Model

In addition to the constant growth DCF model, Mr. Hevert employed a multi-stage (three-stage) DCF analysis, which allows different growth rates to be specified for different time frames. For the initial growth stage, Mr. Hevert used the same analysts' growth rates and retention growth rate as used in the constant growth DCF model. For the long-term, Mr. Hevert used a long-term GDP nominal growth rate of 5.48%, based on the real GDP growth rate of 3.22% from 1929 through 2016 and an inflation rate of 2.19%. The medium-term growth rate is a transition from the short-term to the long-term growth rate. Mr. Hevert's multi-stage analysis produces an indicated ROE range of 7.91% to 11.19%. As with his constant growth DCF model, Mr. Hevert derives the range by using the individual high and low long-term growth estimates for the initial stage growth component.

Staff also conducted a multi-stage DCF analysis based on the two-step DCF methodology employed for several years by the Federal Energy Regulatory Commission (FERC) in determining ROE for natural gas and oil pipeline industries and recently extended to the electric utility industry.[4] In describing its two-step methodology for determining the growth component, FERC explained:

> The Commission uses a two-step procedure for determining the constant dividend growth component of the model, averaging short-term and long-term growth estimates. Security analysts' five-year forecasts for each company in the proxy group, as published by the Institutional Brokers Estimate System (IBES), are used for determining growth for the short term; earnings forecasts made by investment analysts are considered to be the best available estimates of short-term dividend growth because they are likely relied on by investors when making their investment decisions. Long-term growth is based on forecasts of long-term growth of the economy as a whole, as reflected in GDP. The short-term forecast receives a two-thirds weighting and the long-term forecast receives a one-third weighting in calculating the growth rate in the DCF model.[5]

As provided in the attached B. A. Exhibit 2, Staff calculated an indicated ROE based on a long-term growth rate calculated consistent with the FERC methodology; that is, a two-thirds weighting of the analysts forecast of short-term growth and a one-third weighting based on the long-term growth of the economy as reflected in GDP. In calculating this weighted growth rate, Staff used a GDP growth rate of 5.48%, the rate calculated by Mr. Hevert. The low, mean and high dividend yield calculations are the same as in the constant growth DCF model. The two-stage DCF model produces an ROE range of 8.33% to 8.44%.

8. Capital Asset Pricing Model

As the Commission has previously recognized, results from an analysis using the Capital Asset Pricing Model (CAPM) provide a useful check on the DCF analysis.[6] The

---

[4] Martha Coakley, Massachusetts Attorney General, et. al. v. Bangor Hydro-Electric Company, et. al. opinion No. 531, "Order on Initial Decision", 147 FERC ¶ 61, 234 (June 19, 2014).

[5] *Id*. at ¶ 17.

[6] *Central Maine Power Company, Proposed Increase In Rates*, Docket No. 92-345, Order at 31 (Dec. 14, 1993).

general idea behind CAPM is that investors need to be compensated in two ways: time value of money and risk. The time value of money is represented by the risk-free (Rf) rate in the formula and compensates the investors for placing money in any investment over a period of time. The other half of the formula represents risk and calculates the amount of compensation the investor needs for taking on additional risk. This is calculated by taking a risk measure (beta) that compares the returns of the asset to the market over a period of time and to the market premium (Rm-Rf).[7]

The general form of the CAPM is:

$$K = Rf + \beta\,(Rm - Rf)$$

where:	R_f =	risk free rate
	R_m =	return on market
	B =	beta
	$R_m - R_f$ =	market risk premium

As a check to the results of the DCF analysis, Staff conducted a CAPM analysis using the Bloomberg and Value Line average beta which was used by Mr. Hevert. Mr. Hevert's CAPM analysis includes an expected market return component on the S&P 500 Index using the constant growth DCF formulation. He derives both the current dividend yield and the long-term growth factors for the S&P 500 as a whole by weighting the individual company dividend yield and long-term growth by the proportion of total market capitalization that each company represents. Mr. Hevert employs both a current 30-year Treasury rate of 2.97% and a near term projected 30-year Treasury rate of 3.43% as the risk-free rate. Mr. Hevert's CAPM calculations result in an indicated ROE of 9.53% to 11.77%.

Consistent with the Commission's preference as indicated in Docket No. 97-580,

[7] http://www.investopedia.com/terms/c/capm.asp

Staff used a current Treasury rate rather than a forecast of interest rates.[8] Staff calculated the most recent 30-day average[9] of the 30-year Treasury rate and used 2.76% as the risk-free rate. Staff has no issue with the methodology used by Mr. Hevert in calculating market parameters based on the S&P 500 and used the model provided by Mr. Hevert with the revised risk free rate to re-calculate the market risk premiums. The results of Staff's CAPM analysis indicates an ROE range of 9.29% to 11.10% as shown in Figure II.5 below.

Figure II.5

CAPM	Risk Free Rate	Beta Coefficient	ROE (Bloomberg derived)	ROE (Value line derived)
Bloomberg beta	2.76%	0.631	9.29%	9.77%
Value line beta	2.76%	0.75	10.53%	11.10%

CAPM Results

Staff has not employed a Risk Premium model as provided by Mr. Hevert. Although Staff does not question the structure of a risk premium model, we do question Mr. Hevert's definition of the risk premium as the difference between *authorized* ROE and a long-term Treasury yield. The cost of capital analysis is essentially an exercise in determining the level of return required by equity investors in the marketplace. Authorized ROE is not necessarily indicative of actual returns realized in the market and may be an incomplete analysis.

---

[8] *Public Utilities Commission, Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design*, Docket No. 97-580, Order (Mar. 19, 1999).

[9] The average was calculated based on the most recent 30 business days as of May 26, 2016, as reported by the Federal Reserve in Statistical Release H.15.

9. Other Data

As noted, the Commission relies on a DCF analysis which is then cross-checked by several different methodologies to ensure the results of the DCF analysis are not inconsistent the Hope-Bluefield standard. Staff conducted a further analysis by looking at RRA's database of all Natural Gas, and Electric rate cases from 1980 through the most recent data available. To ensure relevance to current market conditions, Staff then focused on a subset of data from 2016 through 2017 to date. Next, any rate cases in that subset in which no ROE was reported were removed. This left 92 rate cases from around the country. This refined data set had an average ROE of 9.71%, with a low of 8.7% to a high of 11.88%.

10. Recommended ROE

In determining its ROE recommendation, Staff depends primarily on the DCF analysis and uses other analyses as a check on the range. The DCF analyses presented by the Company and Staff produce an indicated ROE that generally falls in the low to mid- 9% range. The CAPM analysis presented, suggests a higher ROE, in the range of 9.3 % to 11%. A review of RRA's database indicates a range of authorized ROE in 2016 and 2017 with an average of 9.71%[10] and a range between 8.7% and 11.88%. These results are summarized in Figure II.6 below.

[10] The average was calculated using the entire RRA dataset as described and not as the average of the low and the high results.

Figure II.6

	Low	High	Mean
Staff Constant Growth DCF	8.24%	9.54%	8.89%
Staff Two-Stage Growth DCF	8.33%	8.44%	8.39%
Staff CAPM (Overall)	9.29%	11.10%	10.20%
OPA DCF (Overall)	NA	NA	9.15%
Hevert Constant Growth DCF (Overall)	7.47%	11.81%	9.64%
Hevert Multi-Stage DCF (Overall)	7.91%	11.19%	9.55%
Hevert CAPM (Overall)	9.53%	11.77%	10.65%
RRA Data	8.70%	11.88%	9.71%
Overall Average	**8.50%**	**10.82%**	**9.52%**

Indicated ROE

Staff is cognizant of the effect that the recent equity market price increases have had on the DCF calculations, specifically with respect to calculating dividend yield. For example, the Dow Jones Industrial Average is up 12-14% and the Vanguard Utilities ETF (Exchange Traded Fund) is up 11.75% since the beginning of 2017. The DCF formulation begins with a calculation of a current dividend yield, which is the current dividend divided by the current or recent market price. As market prices increase, the dividend yield goes down. Without any concurrent increase in dividends or revisions to the long-term expected growth rates used in the analysis, a strong market represented by increases in stock prices has the effect of reducing indicated ROE. In this case, it may be appropriate to conclude that the indicated ROE lies toward the high end of the DCF results, particularly because the CAPM results suggest a higher return. As shown in Figure II.6 above, the overall results suggest than an ROE between 9% and 10% would be appropriate. Staff recommends that Northern's ROE be authorized at 9.50%.

11. Capital Structure

The Company proposes a capital structure that consists of 51.7% common equity and 48.3% long-term debt. Mr. Hevert's testimony includes calculations showing that the proxy group actual capital structure is 49.74% common equity and 50.26 % long-term debt. As noted in its testimony, the OPA recommends revising the capital structure to reflect the retirement of $10 million in 6.95% debt in December 2017 and the issuance of $50 million in new long-term debt during the pendency of this case. Those revisions would result in a capital structure that is 45.62% common equity and 54.38% long-term debt. Neither the Company nor the OPA include a component of short-term debt in the proposed capital structure.

As an initial capital structure matter, Staff believes it is appropriate to include a component of short-term debt in the Company's capital structure to represent working capital and other day-to-day operational needs. In its calculation of rate base, Northern includes $2,484,147 in cash working capital based on the lead-lag study presented in the testimony of Mr. Hanson. Staff included this amount of short-term debt in the Company's proposed capital structure and recalculated the capital structure ratios, which resulted in a short-term debt component of 0.82%. Although this ratio of short-term debt may be low, Staff has used it in its proposed capital structure.

The capital structure proposed by the Company and the OPA both represent calculations done at a point in time and may not be appropriate for rate-making purposes. For example, Northern derives its proposed capital structure based on the year-end 2016 balances of long-term debt outstanding and common equity. If, alternatively, Northern's capital structure were revised to include the short-term debt outstanding as of year-end 2016 of just under $37 million, the resulting capital structure would be roughly 43% long-term debt, 46% common equity and 11% short-term debt.

As noted, the revisions to the capital structure proposed by the OPA would result in a common equity ratio of 45.6%.

Rather than using a capital structure based on a specific point in time, which is susceptible to wide variability over time and with adjustments, Staff recommends the use of a hypothetical equity layer of 50% and the resulting overall capital structure as shown in Figure II.7. The use of a hypothetical equity ratio and capital structure is not unusual and has been previously employed by this Commission. It may be particularly fitting to employ a hypothetical capital structure when establishing rates for a subsidiary of a larger utility holding company which may have a different reported capital structure. In response to ODR-001-007, Northern provided the capital structure of its publicly traded parent, Unitil Corporation, showing the common equity ratio of Unitil for 2014-2016 was 44% to 46%. A 50% common equity ratio is slightly above the 49.74% common equity ratio of the proxy group as calculated by Mr. Hevert. Additionally, using RRA's database and looking at natural gas rate decisions in 2016 and 2017, the average common equity ratio for natural gas utilities was 47.41%. Thus, an equity ratio of 50% is reasonable.

Figure II.7

Northern Staff Bench Analysis		
Capital Structure		
		Ratios
Long-Term Debt		49.18%
Short-Term Debt		0.82%
Preferred Stock		0.00%
Common Stock		50.00%
		100.00%

Capital Structure

12. Cost of Short-term and Long-Term Debt

Although the Company did not include a component of short-term debt in its capital structure, in Schedule RevReq-6, Northern specifies a 2.19% cost of short-term debt and provided supporting detail of recent short-term debt costs. The 2.19% is the short-term debt rate for March 2017 and Staff has used this rate in the calculation of overall WACC. Staff recommends updating the short-term debt cost for more recent market rates in the Examiner's Report.

In its testimony, the OPA recommends revising both the capital structure and the cost of long-term debt to reflect the retirement of $10 million in 6.95% debt in December 2017 and the issuance of $50 million in new long-term debt at a weighted average cost of 4.00% in November 2017. Staff agrees that the recommended reduction in the overall cost of long-term debt is appropriate to make as a known and measurable change. Northern will retire $10 million in higher priced long-term debt before the end of this case and has priced and will issue $50 million in relatively lower priced long-term debt. In response to ODR-003-032, the Company calculated that these upcoming changes in long-term debt would reduce the weighted debt cost from 6.16% to 5.55%. Staff has incorporated this reduction in long-term debt cost in the overall recommended WACC calculation. As noted, with the addition of the short-term debt component and the use of a hypothetical capital structure which includes a common equity ratio of 50%, Staff finds the Company's capital structure to be reasonable and its common equity ratio to be within the range established by the proxy group and other recent utility rate decisions.

13. Weighted Average Cost of Capital (WACC)

Combining the Staff recommended ROE of 9.50%, the recommended capital structure and the adjustment to the cost of long-term debt to reflect known and measurable changes results in a pre-tax weighted average cost of capital of 10.65% for Northern as shown in Figure II.8 below.

Figure II.8

Northern Staff Bench Analysis					
Weighted Average Cost of Capital					
Capital Structure		**Ratios**	**Rate**	**Cost**	**Pre-Tax WACC**
					Tax Gross up 39.89%
Long-Term Debt		49.18%	5.55%	2.73%	2.73%
Short-Term Debt		0.82%	2.19%	0.02%	0.02%
Preferred Stock		0.00%	0.00%	0.00%	0.00%
Common Stock		50.00%	9.50%	4.75%	7.90%
		100.00%		7.50%	
	Pre-Tax Weighted Average Cost of Capital				**10.65%**

Staff Recommended Capital Structure, Debt Cost and ROE

C. Depreciation

The Staff's recommendations on the depreciation issues are contained in the report of its consultant, William Dunkel, which is attached as Bench Analysis Attachment A.

D. O&M Expense

1. Inflation Adjustment

The Company proposes an inflation allowance adjustment to its operating and maintenance (O&M) expenses in the amount of $150,416. This amount is calculated by applying the Company's projected inflation rate for the period July 1, 2016 to March 1, 2018 of 3.63% to its residual O&M expenses; the expenses that have not been adjusted for other known and measurable changes or are not subject to inflation. Schedule RevReq-3-15. While the Company's inflation based forecast of O&M expenses is an appropriate component of an attrition (or rate-effective) revenue requirement analysis, the Company has not included an attrition analysis in this case. Had they done so, the Company would also have included a forecast of rate effective year sales.

Northern's proposed inflation adjustment results in O&M expenses being included in its revenue requirements at rate effective year levels but the revenues at test year levels resulting in a mismatch between the two sides of the revenue requirement equation. The inflation adjustment is not known and measurable and it is not appropriate to include as a known and measurable adjustment of O&M expense. Therefore, Staff recommends that this adjustment be removed from the calculation of revenue requirements in this case.

2. Rate Case Expenses

Northern has included a proforma reduction of $75,752 to its amortization expense related to its rate case expense. The Company estimated total rate case expenses of $400,000 which it proposes to amortize over four years resulting in an estimated annual rate case expense of $100,000. The adjustment amount was calculated by removing $175,752 related to the prior rate case expenses from the test year amortization expenses and adding the $100,000 estimated annual rate case expense for this docket, equaling a net reduction of $75,752. RevReq 3-19.

Staff agrees with the inclusion of a rate case expense adjustment and is generally in agreement with the methodology used to calculate the adjustment including the proposed four-year period. The Staff would note, however, the proper rate case expense recovery mechanism is normalization and not amortization. Staff also notes that as of August 8, 2017, the Company had incurred only $23,175 in external legal fees versus the estimated $100,000. ODR-003-015. Similarly, as of July 8, 2017, Northern had incurred $10,823 related to its return on equity consultant versus the $85,000 originally estimated. Actual rate case expenses should be used to calculate the adjustment. Staff expects the Company to update the adjustment amount to reflect actual rate cases expenses prior to finalizing the revenue requirement.

3. Incentive Compensation

Northern has included incentive compensation, which it provides as a part of the total compensation package to employees, as part of its revenue requirement. The Company offers three different incentive plans: Incentive Plan, Management Incentive Plan and a Stock Plan. The Incentive Plan is available to employees of eligible subsidiaries, including Northern and USC, who are not eligible for the Management Incentive Plan. The Management Incentive Plan is available to designated management employees. The Stock Plan appears to be available to all employees. The accounting for each plan is similar in that costs are expensed or capitalized based upon where the employees' time is recorded.

The payment of incentive plan compensation is dependent on evaluation of certain metrics and the requirement that target levels of performance are met. The quantitative evaluation areas are Earnings Per Share; Gas Safety – Response to Odor Calls; Electric Reliability – SAIDI Minutes; Customer Satisfaction; and O&M Cost Per Customer. From reviewing the plans filed in OPA-004-013, the objective of the two incentive plans is to provide an incentive to employees to "motivate them to maximize their efforts on the Corporation's behalf." Staff believes that the incentive compensation related to Earnings Per Share, which accounts for 40% of the target-level payout, generally is intended to provide benefits to shareholders rather than to ratepayers. In addition, Staff does not agree that Northern ratepayers should incur costs for incentives paid to achieve electric reliability standards, which accounts for an additional 10% of the target-level payment. Staff recommends adjustments to reduce test year O&M

expenses to reflect these views.

Northern's test year incentive payments were $1,343,753 which includes Northern direct costs as well as costs incurred through USC. Northern capitalized 50.29% of its costs and 31.90% of the USC costs, which reduces the incentive payments recorded in the test year O&M costs. In addition, Northern adjusted the test year O&M incentive compensation as the 2016 incentive payments exceeded the target. Northern reduced the test year expense by the amount which exceeded what the payment would have been if payment had been made at target levels. Staff agrees with these calculations and has calculated its proposed adjustment at the target incentive levels.

Staff interprets the Restricted Stock Plan to be 100% associated with earnings and, therefore, benefiting shareholders and not ratepayers. The Plan states that the objectives are to "optimize the profitability and growth of the Company through incentives which are consistent with the Company's goals and which link the personal interests of Participants to those of the Company's shareholders…" OPA-004-013 Attachment 3, section 1.2. As a result, Staff recommends that all incentive compensation payments related to the Stock Plan be excluded from the revenue requirement calculation.

As noted above, the Company included a reduction to test year O&M expenses of $176,181 to account for incentive compensation being made at above target levels. Staff recommends an additional reduction to O&M expenses of $554,655 to account for the exclusion of incentive payments related earnings per share and electric reliability goals. The calculation is detailed in B.A. Exhibit 3.

4. <u>Bad Debt Expense</u>

Northern included Distribution Bad Debt expense in its revenue requirements based upon the net write-offs as a percentage of Delivery Retail Billed Revenues multiplied by the Normalized Delivery Retail Billed Revenues after the increase in revenues from the rate case. Chong Dir. Test., Rev.Req. 3-8. Therefore, the bad debt expense shall have to be adjusted to reflect the change in the additional revenues allowed in the rate case. As Staff was unable to determine the full impact on the revenues from the adjustments proposed by the OPA and in the Bench Analysis, we have not calculated a test year adjustment due to bad debt expense. However, the adjustment will be calculated by multiplying 0.89% by any change in the allowed rate year revenues.

5. Amortization of the Gain on the Sale of Property

As discussed in Section II(A)(1), the Company should recognize a regulatory liability associated with its gain on the sale of its Forest Avenue property. Amortization of this liability over a four-year period results in a reduction in expense of $230,528.

E. Sales Revenue

The Company has used test year 2016 operating revenues in the determination of its revenue deficiency as detailed on schedule Chong Dir. Test. Rev.Req.-2. Test year revenues were adjusted for weather normalization, unbilled revenue, 2016 & 2017 TIRA annualization, non-distribution bad debt and lost revenue resulting from the loss of one large customer. Northern has not performed an attrition analysis.

The Company's rate base is based on test year-end balances. Staff's position is that year-end rate base most appropriately matches to 2017 revenues and, therefore, 2017 actual revenue should be used as a known and measurable change in calculating the revenue deficiency. When available, the Company should update schedule RevReq-2 with applicable 2017 amounts, using actual amounts where available and estimates where necessary. In addition, Northern should update the weather normalization, unbilled revenue and non-distribution bad debt adjustments to reflect appropriate adjustments to 2017 sales. The 2016 TIRA annualization and large customer lost revenue adjustments will not be applicable as 2017 would already fully reflect the impact of those changes.

III. TAB REVENUE REQUIREMENTS

A. Overview

On June 5, 2015, Unitil submitted a Request for Commission Approval of its Saco TAB Program. Unitil described the TAB program as being designed to provide the Company with a mechanism to build-out its distribution network incrementally in targeted areas to serve new customers who are currently off the main line. Unitil explained that customers who are off the main line are typically required to pay a contribution in aid of construction (CIAC) up front before Unitil can extend the main line and install a new service for the customer and that the CIAC is a significant barrier to consumers choosing to convert to natural gas. The TAB program would remove the CIAC barrier by replacing it with a monthly surcharge mechanism in specifically defined geographic areas in the City of Saco. The Company would assess a TAB surcharge to customers within the TAB expansion area for a 10-year period which is intended to recover the costs of the expansion over time from those customers that benefit from the expansion. Unitil proposed that its TAB program take effect on January 1, 2016. On December 22, 2015, the Commission issued an Order Approving Stipulation which authorized Northern's Saco TAB Program.

As noted previously, the Company's initial filing did not contain a request for recovery of any costs related to the Saco TAB. However, the Company submitted a supplemental filing on August 18, 2017, which requested that it be allowed to increase its rates by an additional $677,000 for Saco TAB revenue requirements. As explained by Mr. Chong in his Supplemental Testimony, the Saco TAB plant was gassed and in service by December 31, 2016, however, the Saco TAB investment was not closed to plant since the Company was still receiving invoices from vendors into 2017.

The Staff agrees with the Company that it is appropriate to address the Saco TAB Revenue Requirement issues in this case. However, the Staff disagrees with the Company's Saco TAB Revenue Requirement calculations. In addition, in order to address the issue of how the risks of the Saco TAB investment should be allocated between the Company and ratepayers, the Staff proposes an alternative ratemaking approach for recovery of the Saco TAB revenue requirement.

B. Revenue Requirement Calculation

1. Rate Base

The Company has included $4,132,346 in plant investment for recovery in this proceeding. The plant investment differs from the $2,764,740 amount that the Company utilized in modeling the Saco TAB surcharge in Docket No. 2015-00146. The Company has explained that the difference is primarily related to the inclusion of overhead in the investment and has confirmed that the overhead amounts incorporated into investment have been removed from test year expense. With this confirmation, the Staff accepts the Company's gross plant calculation of $4,132,346.

In its modeling in Docket No. 2015-00146 to calculate the TAB Rate Base level, the Company deducted from gross plant investment amounts for accumulated depreciation, the TAB surcharge revenue and accumulated deferred income taxes. In its TAB revenue requirement proposal, however, the Company has failed to include any such deductions. Using the Staff's proposed depreciation rates as discussed below, the Staff estimates the first year offset to plant for accumulated depreciation to be $89,247.

At the September 19, 2017 Technical Conference, the Company confirmed that its 2016 Saco TAB plant investment was eligible for bonus tax depreciation treatment. Therefore, the Staff has included as an offset to gross plant investment $788,596 for deferred taxes, including bonus depreciation. In addition, the Staff reduced the gross plant investment by the TAB surcharge revenue through 2017 which the Staff now estimates to be $30,702. This amount should be updated based on actual amounts at the end of the case.

Making the adjustments discussed above to gross plant results in a net plant investment of $3,226,055. B.A. Exhibit 4, pg. 3.

2. Return on Investment

Applying the Staff's proposed pre-tax WACC of 10.65%, results in a required return of $343,421 on the Company's Saco TAB rate base. B.A. Exhibit 4, pg. 1.

3. Depreciation Expense

Applying the depreciation rates proposed by Staff's consultant to the Saco TAB investment, reduces annual depreciation expenses from $108,025 to $89,247. B.A. Exhibit 4, pg. 2.

4. Property Tax Expense

The Company has updated its Saco TAB property tax expense based on a known and measurable increase in the costs of Saco mil rate from 1.53% to 1.94%. The Staff accepts the Company's adjustment as a known and measurable change based on 2017 data.

5. Saco TAB Revenues

The Company here has included in revenue requirements 2016 end of year plant investment along with 2017 expenses but has excluded entirely the revenue that will be received which is related to such investment and expense. For reasons similar to those discussed in Section II(E), the Staff proposes that 2017 Saco TAB income be included as an offset to Revenue Requirements. The Company has estimated 2017 revenue of $142,573. The Company's estimate appears to omit revenue from its one large (G51 class) customer in the TAB area. The Staff has modelled 2017 revenue from this customer to be $7,236. B.A. Exhibit 4, pg. 3. The Company should as part of its rebuttal case, provide an update on the amount of Saco TAB revenue received in 2017 including revenue from the G51 customer.

6. <u>Saco TAB Revenue Deficiency</u>

Based on the above proposed calculations and assumptions, the Staff estimates the Saco TAB Revenue deficiency to be $362,894. B.A. Exhibit 4, pg. 1. .

7. <u>Alternative Ratemaking for Saco TAB Revenue Requirements</u>

In approving the Saco TAB program, the Commission noted that utilizing the TAB surcharge in lieu of the traditional CIAC was a novel approach to attracting new customers. The Commission went on to state, however, that:

> "Nonetheless, in view of the uncertainty as to the projected rate of conversion to natural gas and the discretion afforded Unitil in the stipulation to respond accordingly, the Commission makes no determination regarding the recoverability of TAB-related costs in a future base rate case proceeding, leaving that ratemaking issue open for consideration at the time Unitil seeks to include any such costs in base rates."

Northern Utilities, Inc., d/b/a Unitil, Request for Approval of Rate Targeted Area Build-Out Program, Docket No. 2015-00146.

By eliminating the CIAC the TAB has, as the Company asserted, removed a barrier for new customers to covert to natural gas. Doing so, however, has shifted substantial amount of the risk associated with the investment, and achieving sales and penetration rates at the levels projected in the Company's TAB modeling, to existing

Northern customers. Therefore, in order to fairly allocate the risk of the investment between the Company and ratepayers and to provide the Company with an incentive to achieve the projected sales levels, the Staff is proposing a Saco TAB incentive mechanism.

The mechanism would work by establishing targeted levels of sales and surcharge revenues based on the Company's modelling in Docket No. 2015-00145. In setting the Revenue Requirement for the Saco TAB in the future, to the extent the Company did not achieve the target sales or surcharge revenue at 90% of the target levels, the deficiency would be impacted to the Company. On the other hand, if the Company achieved sales or surcharge revenue in excess of 110% of the target, such amounts would flow to the Company. The mechanism would be specific to the buildout areas approved by the Commission in Docket No. 2015-00145.

IV. TIRA ADJUSTMENT MECHANISM

A. Background

The original Targeted Infrastructure Replacement Adjustment mechanism (TIRA 1) was approved by the Commission in its December 27, 2013 Order Approving Stipulation in Docket No. 2013-00133, which was the Company's most recent base rate case. TIRA 1, which was established for a four-year period, is a "capital tracker" that allows for recovery in rates of the costs associated with certain of the Company's capital programs, specifically, the Cast Iron Replacement Program (CIRP), the Unprotected Steel Replacement Program (UPS), and the Farm Tap Regulator Program (FTR).

The CIRP is a fourteen-year (2011-2024) construction project to replace approximately 70 miles of cast iron, wrought iron, and unprotected steel pipe in the Company's low pressure distribution system in Portland and Westbrook and perform related system improvements. The CIRP also involves a pressure conversion, from low-pressure to intermediate pressure, which will allow the system to better accommodate customer growth. The CIRP was motivated by safety concerns stemming from the age and leak-prone nature of this pipe in this portion of the Company's system. The parameters of the CIRP, including the project scope and schedule, were approved by the Commission in its July 30, 2010 Order Approving Stipulation in Docket No. 2008-00151. (CIRP Order)

The UPS, which began in 2014, is a project to replace approximately 10 miles of unprotected steel mains and services on the Company's intermediate pressure system. As with the CIRP, the UPS was motivated by safety concerns about the potential for corrosion of the unprotected pipe. The FTR, which also began in 2014, involves the replacement of more than 100 direct buried pressure regulating devices with new regulators that will be installed in an enclosure to shield the device from direct contact with the ground.

Pursuant to TIRA 1, rates have been adjusted on May 1 of each year (2014-2017) to reflect recovery of investments made in the prior calendar year (2013-2016) for the CIRP, UPS and FTR programs, subject to certain conditions. The conditions include the Company meeting certain cost and schedule metrics which are set by reference to the Company's Earned Value Management (EVM) model. The last rate adjustment under TIRA 1 was effective May 1, 2017.

As described by the Company, (e.g., in its filing in Docket No. 2017-00035), EVM is a valuable and widely-used project management practice to track performance. EVM requires an up-front, well-defined scope of work and budget for each discrete component of a project, as well as defined metrics. Performance can then be tracked by comparing actual work completed and actual cost against the metrics. The Company's EVM for the CIRP, UPS and FTR programs established planning estimates, on a per unit basis for each component of the program, for: (1) the quantity of units to be installed in each year; and (2) the cost per unit. Given the length, scope and complexity of projects like the CIRP, EVM allows overall progress to be tracked even if actual work on a year-to-year basis diverges from the original plan. As discussed below, certain key elements of TIRA 1 were established based on the EVM that had been developed by the Company prior to starting construction on the CIRP, UPS, and FT programs and, at least in the case of the CIRP, prior to its TIRA proposal.

Under TIRA 1, annual rate adjustments were subject to the Company meeting two performance metrics; one that measured its cost performance and one that measured its schedule performance. The Cost Performance Index (CPI) and Schedule Performance Index (SPI) were set by reference to the Planned Value (PV) and Earned Value (EV) at a given point during the project as reflected by the values in the Company's EVM model. Specifically, the aggregate of the per unit quantity and cost values reflected in the EVM established the Planned Value (PV) for each year against which actual performance was tracked. The Earned Value (EV), then, was calculated as the product of the units actually installed in each year on a cumulative basis and the originally estimated cost per unit.

The CPI was defined by the relationship between Earned Value and Actual Cost, specifically EV/AC. If the cumulative Earned Value was equal to or greater than the cumulative Actual Cost (which translates to a CPI => 1.0), the project would be considered to be under budget. Conversely, if the Actual Cost exceeded the Earned Value (CPI < 1.0) the project would be considered to be over budget. The SPI was defined by the relationship between Planned Value and Earned Value, specifically EV/PV. If the Earned Value exceeded the Planned Value, (SPI => 1.0), the project would be considered to be ahead of schedule and, if not, the project would be considered to be behind schedule.

Under TIRA 1, a rate adjustment would be made only if the Company was meeting both the Cost Performance Index and the Schedule Performance Index. Specifically, both indices must, on a cumulative basis since the start of the program, be equal to or greater than 1.0. If either the CPI or the SPI was less than 1.0, TIRA 1 would have been suspended pending a review by the Commission of the reasonableness of the Company's performance. To date, as shown in Figure IV.1 below, in each year the Company has met both the CPI and SPI, although, in some years, the CPI has been very close to 1.0.[11]

Figure IV.1

	Annual		Cumulative	
Year	CPI	SPI	CPI	SPI
2011	1.19	1.05	1.19	1.05
2012	1.12	1.15	1.15	1.11
2013	0.95	1.39	1.08	1.19
2014	0.98	0.97	1.05	1.12
2015	0.89	1.34	1.004	1.17
2016	1.04	0.99	1.01	1.14

The annual rate increase under TIRA 1 was capped at 4%. TIRA 1 also included an Earning Sharing Mechanism (ESM) pursuant to which (1) earnings between 10% and 11% would be shared on a 50/50 basis between the Company and ratepayers and (2) earnings in excess of 11% would be returned to ratepayers. Neither the Rate Cap nor the ESM was triggered under TIRA 1. Figure IV.2 below provides the percentage rate increases for each year of TIRA 1.

[11] Figure IV.1 includes the CPI and SPI for the entire construction period, a portion of which pre-dates the TIRA.

Figure IV.2

TIRA 1 Rate Adjustments

Docket	**2014-00059**	**2015-00054**	**2016-00033**	**2017-00035**
Effective Date	**05/01/2014**	**05/01/2015**	**05/01/2016**	**05/01/2017**
Revenue Requirement Year	**2013**	**2014**	**2015**	**2016**
Weather Normalized Distribution Revenues	$34,820,388	$38,245,776	$40,571,502	$42,209,471
TIRA Rate Base	$7,929,942	$16,229,488	$25,880,698	$33,274,588
Incremental TIRA Revenue Requirement	$1,287,956	$1,154,626	$1,539,337	$1,102,389
Total TIRA Revenue Requirement	$1,287,956	$2,442,582	$3,981,919	$5,084,307
Increase as % of Distribution Revenues	3.70%	3.02%	3.79%	2.61%

Source of data: Company filing in Docket No. 2017-00035; Exhibit DLC-1, p.1

Described generally, the TIRA rate adjustments in each year reflected the difference between the CIRP, UPS and FTR related revenue requirement in the prior calendar year and the revenue requirement for these programs for the calendar year before that. Under TIRA 1, the return on rate base was 11%, which was less than the return for the rest of the Company's rate base allowed by the Order Approving Stipulation in Docket No. 2013-00133.

B. Actual Costs and Revised EVM model

As described in the Leblanc/Sprague testimony, the Company is proposing to amend the scope and cost of the CIRP, UPS, and FTR programs to reflect its clearer understanding, gained from almost seven years of construction experience, of the requirements of the program. According to Leblanc/Sprague, "Northern has a clearer understanding of the actual condition and composition of its underground distribution system, which allows the Company to more accurately estimate the scope of work that remains necessary to complete the CIRP/UPS/FT." Leblanc/Sprague Dir. Test. at 4. The Company would amend its EVM model accordingly, and is proposing to use the amended EVM model to measure the CPI and SPI under its proposed TIRA extension.

1. Actual Costs 2011-2016

During the first several years of construction of the CIRP, UPS and FTR programs, actual costs exceeded the Company's original estimates by about $9.1 million, or approximately 33%. Figure IV.3 below provides a summary of these cost variances by category.

Figure IV.3

Northern Utilities CIRP/UPS/FT EVM
Original Plan vs. Actual Cost; 2011-2016
Nominal Dollars

Item	Original Estimate	Actual Cost	$ Delta Actual Cost/ Original Estimate	Percent Delta Actual Cost/ Original Estimate
CIRP				
Main Installation	$9,651,110	$18,158,158	$8,507,047	88.1%
Critical & System Valves	$84,529	$0	($84,529)	-100.0%
Service Renewals	$10,932,513	$7,850,818	($3,081,695)	-28.2%
Meter Work	$1,924,978	$1,708,993	($215,985)	-11.2%
System Uprates	$2,420,197	$2,174,371	($245,826)	-10.2%
Regulator Stations	$223,139	$879,489	$656,350	294.1%
System Improvements	$917,035	$2,434,357	$1,517,323	165.5%
UPS				
Main Installation	$702,427	$2,365,401	$1,662,974	236.7%
Service Renewals	$408,599	$489,563	$80,964	19.8%
Meter Work	$31,829	$47,234	$15,405	48.4%
FTR				
Farm Tap Regulators	$401,821	$687,821	$286,000	71.2%
TOTAL (w/o PM and contingency)	$27,698,178	$36,796,206	$9,098,027	32.8%

Source of data: Company filing in 2017-00035 and response to EX-002-005 in 2017-00065.

As shown above, the vast majority of the difference between estimated and actual costs is attributable to main installations. According to the Company, these main-related increases were primarily caused by two factors: (1) the need to direct-bury rather than insert new main; and (2) unanticipated permitting and compliance costs resulting from stricter-than-expected enforcement of codes and ordinances by the City of Portland, which principally consists of street opening permits, pavement restoration and working conditions (e.g., night and weekend work). These two factors are related because compliance with Portland's street opening permit process involves factors that may also affect the direct bury process, e.g., the pavement restoration process.

Regarding the need to direct bury more pipe, the Company stated that it is more expensive to install a mile of main by direct bury when compared to pipe insertion.[12] When the cost of the CIRP was initially estimated, the Company believed it would need to replace 69 miles of cast iron and unprotected steel main, and that about 65% of the new main (*i.e.*, about 45 miles) could be installed using insertion. Based on this ratio of 65% insertion to 35% open trench, the Company derived a blended average per mile cost for main installations of $303,937. During the first six years of the CIRP, however, the Company stated it was only able to use insertion for about 43% of the new mains installed. Because a greater proportion of mains are being replaced by the more expensive open trench method than initially estimated, the actual average cost per mile of installed mains was much higher than the original blended cost estimate. LeBlanc/Sprague Dir. Test. at 13.

For the reasons discussed below, Staff is concerned that the Company may not have a comprehensive understanding of the causes of the increased costs in the CIRP, UPS, and FTR programs, and that it may have not have taken all the steps it could have to address the cost increases, such as more strenuously negotiating with the City of Portland regarding street opening conditions. This lack of push-back against the City of Portland, may, in part, be due to the structure of TIRA 1 which allowed for recovery of

---

[12] "Direct bury," also referred to as "open trench construction," requires that a trench for the main be excavated to the appropriate depth for the entire length of the main being installed. After the main has been lowered into the trench it is backfilled, compacted and the pavement is restored. "Pipe insertion" is a construction technique that allows a new plastic main to be installed inside a larger existing underground low-pressure cast iron or steel gas main. Pipe insertion provides significant cost savings over direct bury construction of a new replacement main, primarily due to the lack of need to open a trench for the entire length of the new main being installed.

actual costs, as long as the Company was meeting the established cost [13] and schedule metrics and the required rate increase was not above 4%. Section IV.4 below provides a further discussion of the reasons TIRA 1 may not have provided a sufficient incentive for the Company to control costs.

The Company states that "…the increased costs (in the CIRP/UPS/FT programs) are primarily attributable to compliance with the City of Portland's street opening permit conditions… ." The Company explains that in 2012, the City made significant changes to its street opening permit process related to street restoration, traffic control, night work and the cost of the permit itself. According to the Company, the City's goal was to reduce disruption to businesses by minimizing or eliminating construction work within the Business District and along the general commuting routes during peak hours. The Company states that the changes to the permit process have required significant amounts of the Company's CIRP work to be performed during nights and weekends, which has made it more expensive to complete. The Company also claims that the permit changes required it to perform costly pavement restoration. The Company stated that it has tried to negotiate with the City over these conditions, but those efforts have been unsuccessful. LeBlanc/Sprague Dir. Test. at 9.

As noted above, the Company indicated that the City made major changes to its street opening permit process in 2012. However, a review of the City's Rules and Regulations for Excavation Activity within the Public Right-of-Way shows that these regulations have been in place since June of 2000. When questioned, the Company

[13] The cost metric included a substantial contingency, which, at least in part, allowed the Company to meet its CPI during TIRA 1 despite main installation costs being much higher than estimated. In addition, the actual cost for CIRP service renewals was less than estimated on a per unit basis, and the unit quantity was higher than estimated, which had a positive effect on the CPI, offsetting the main-related cost increases.

indicated that the regulations had not actually changed in 2012, rather, the City began to “strictly scrutinize” the Company’s plans. The Company noted that, prior to 2012, the City was more collaborative and allowed the Company to plan and manage its own traffic control plans and to use its discretion regarding pavement restoration of excavated surfaces such as cobblestone and concrete. ODR 2-4.

The Company stated in its testimony that it has tried to negotiate with the City over these conditions. However, there is little evidence in the record to substantiate this claim. The Company provided information showing that in 2013 its contractor, NEUCO, was fined $75,250 for undertaking an excavation without a permit. The fine was later waived because the City failed to follow the violation and penalty provisions of its Street Opening Ordinance. The Company also provided information showing that in November of 2013, the Company appealed a change in the City’s permit fee calculation process that increased the Company’s typical street opening fee from $7,020 to $40,230. The Company and the City informally agreed to “stay” the appeal and attempt to negotiate a Memorandum of Understanding (MOU). Negotiations continued in 2014, where the City billed the Company $38,190 for street opening fees when, according to the Company, the typical fee would have been $7,290. Negotiations continued and in 2016, the City and the Company agreed that any agreement on permit fees would also include an agreement on street opening restoration. To Staff’s knowledge, an agreement has not yet been reached.

Staff notes that the amount of money related to the cost of the street opening permits described above is relatively small; the difference between the Company’s position and the City’s position being approximately $35,000 per year. For the period of 2013 through 2016, this amounts to approximately $120,000. This amount is insignificant in relation to the cost increases experienced for the CIRP, UPS, and FTR programs. Further, it appears from the record that the Company has not paid the disputed amount and it is not clear whether it will ultimately be responsible for paying the disputed amount.

Although the record shows that the Company and the City had numerous discussions related to the cost of street opening permits themselves and the NEUCO fine, there is little evidence that the Company sought to negotiate with the City over the street opening permit *conditions* to which it attributes the cost increases, such as night and weekend work, traffic control plans, etc. Furthermore, there is little evidence provided to document what actual conditions were placed on the Company by the City through the permit process. According to the Company, the permit conditions, whether it be asphalt restoration or night work, are not stated in the permit. Rather, the conditions were established through verbal communication during the permitting process. Thus, there is no written evidence of what conditions the Company was required to follow in its construction activities, even though the Company claims that these conditions are a major cause of the CIRP, UPS, and FTR program cost increases. Finally, in response to questioning, the Company acknowledged that it actually did not attempt to negotiate with the City regarding these requirements because the Company assumed that the City would not be willing to negotiate. TR. 68-69 (Aug. 3, 2017).

In addition, a review of the actual cost per mile for main installation statistics shown in Figure IV.4 below do not demonstrate a correlation between the street opening permit conditions required by the City of Portland beginning 2012 and the cost increases experienced by the CIRP, UPS, and FTR programs.

Figure IV.4

Actual Cost Per Mile 2011 - 2016									
Year	Insertion			Direct Burial			Total Cost	Total Miles	Avg. Cost/Mile
	Miles	Cost	$/mile	Miles	Cost	$/mile			
2011	2.43	$245,113.58	$ 100,869.79	2.76	$ 2,513,270.11	$910,605.11	$2,758,383.69	5.19	$531,480.48
2012	2.07	$428,563.50	$ 207,035.51	3.32	$1,716,240.37	$516,939.87	$2,144,803.87	5.39	$397,922.80
2013	3.74	$788,767.53	$ 210,900.41	3.58	$ 2,405,435.78	$671,909.44	$3,194,203.31	7.32	$436,366.57
2014	1.31	$467,413.73	$ 356,804.37	2.03	$1,902,700.69	$937,290.98	$2,370,114.42	3.34	$709,615.10
2015	1.25	$ 233,511.64	$ 186,809.31	4.03	$2,385,504.28	$591,936.55	$2,619,015.92	5.28	$496,025.74
2016	1.71	$1,620,552.83	$ 947,691.71	0.73	$1,093,322.72	$1,497,702.36	$2,713,875.55	2.44	$1,112,244.08
Total	12.51	$3,783,922.81	$ 302,471.85	16.45	$12,016,473.95	$730,484.74	$15,800,396.76	28.96	$545,593.81

Source of data: ODR 2-1, Attach. 1

In particular, Figure IV.4 shows that the actual direct bury cost per mile for mains in 2011, the year *before* the City of Portland implemented its changes to the street opening process, was $910,605. This amount is significantly higher than the actual per mile direct bury cost experienced by the Company in 2012, 2013, and 2015, all of which were years when the City's revised street opening permit processes were in effect.

Staff also notes that the actual per mile cost of insertion experienced by the Company in 2016, $947,692, was significantly higher than the actual direct bury costs experienced by the Company in 2012, 2013, and 2015. Although there may be reasons for this, on its face it appears inconsistent with the Company's statements that the cost to insert pipe is significantly less than the cost to direct bury pipe.

As discussed below, given the experience under TIRA 1, Staff is proposing that any extension of the TIRA include design changes to provide stronger incentives for cost control.

2. <u>Revised EVM</u>

As noted above, the Company is proposing to revise its EVM model to reflect its expected scope and cost for the remaining years of construction (2017-2024). Compared to the original EVM, the revised EVM reflects an increase in project costs of about $15 million, or 30%, during these years. Figure IV.5 below shows the variance by category.

Figure IV.5

Northern Utilities CIRP/UPS/FT EVM
2017 - 2024 Comparison
Real 2017$

Item	Original EVM Total Cost 2017-2024	Updated EVM Total Cost (2017-2024)	$ Delta Total Cost	Percent Delta Total Cost
CIRP				
Main Installation	$13,895,865	$24,066,263	$10,170,398	73.2%
Critical & System Valves	$144,504		($144,504)	-100.0%
Service Renewals	$12,401,031	$13,702,036	$1,301,005	10.5%
Meter Work	$2,303,222	$2,563,237	$260,015	11.3%
System Uprates	$1,407,107	$2,750,715	$1,343,608	95.5%
Regulator Stations	$390,225	$156,972	($233,253)	-59.8%
System Improvements	$2,385,799	$821,904	($1,563,895)	-65.6%
UPS		$0	$0	
Main Installation	$4,839,026	$6,610,233	$1,771,207	36.6%
Service Renewals	$2,951,815	$3,807,182	$855,367	29.0%
Meter Work	$234,029	$323,395	$89,366	38.2%
FTR		$0	$0	
Farm Tap Regulators	$767,909	$557,083	($210,826)	-27.5%
SubTotal	$41,720,532	$55,359,020	$13,638,488	32.7%
PM and Contingency	$8,260,665	$9,721,044	$1,460,379	17.7%
Total Project Cost	$49,981,197	$65,080,064	$15,098,867	30.2%

Source of data: Company filing in 2017-00035 and Exhibit CLSK-1 (corrected)

When both actual costs through 2016 and updated cost estimates through 2024 are compared to the original estimates for the entire project construction period, the project cost has grown from $87 million to just over $111 million, a difference of about $24 million, or about 28%.

C. Company Proposal for a TIRA Extension

The Company is proposing to extend the TIRA for an additional four-year period (TIRA 2). The proposed TIRA 2 would be similar to the original TIRA, however the Company is proposing the following changes: (1) an adjustment to the O&M offset; (2) inclusion of the costs associated with Excess Flow Valves (EFV); (3) an increase in the pre-tax return on rate base from 11.0% to 11.83%; (4) an increase in the rate cap from

4% to 5%; and, (5) most importantly, the Company would use its revised EVM model to establish the cost and schedule performance indices.

1. O&M Offset

TIRA 1 included an O&M Offset to reflect the expected reduction in O&M expenses as leak-prone mains were removed from service. The amount of the offset was based on the Company's estimate of $5,544 per mile. The Company is proposing to increase the O&M Offset to $7,614 per mile, based on its most recent history. As shown in Exhibit CLKS-3, this amount reflects actual experience during the three-year period 2014-2016. According to Company witnesses Mr. Leblanc and Mr. Sprague, the increase is driven by general inflation and the types and locations of leak repairs.

Staff agrees that, if the TIRA is extended, the O&M Offset should be updated, and does not disagree with basing the update on the Company's proposed $7,614 per mile offset. However, given that the O&M expenses that will be avoided are subject to inflation-driven increases, Staff proposes that the offset be increased each year to reflect general inflation. This is particularly important given the Staff's proposed term for TIRA 2. (See Section IV(D)(3)(i) below.) As noted above, the Company's proposed $7,614 value reflects the average cost during the period 2014-2016. Thus, for the first rate adjustment under TIRA 2, which would presumably occur in May of 2018, the O&M Offset should be increased to reflect inflation from 2015 to 2017, and then also in each subsequent year. These inflation adjustments should be made by reference to the Gross Domestic Product Implicit Price Deflator (GDP-IPD).

2. Excess Flow Valves

On December 4, 2009, the Federal Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) amended 49 CFR Part 192 to require operators of natural gas distribution pipelines to install excess flow valves

(EFVs) on all new and replaced service lines to single family residential homes.[14] 49 CFR 192.383(a). On October 14, 2015, PHMSA extended this requirement to include branched distribution lines serving single family residential homes, multi-family residences, and small commercial entities consuming gas volumes not to exceed 1,000 standard cubic feet per hour. PHMSA's amended regulations also required operators of natural gas distribution lines to install EFVs on existing customer service lines if requested by the customer and to notify customers of their right to request the installation of an EFV on their service lines. If an existing customer requests the installation of an EFV, an operator must install the EFV at a mutually agreeable date. Finally, PHMSA's regulations specify that "the operator's rate-setter determines how and to whom the costs of the requested EFVs are distributed." 49 CFR Part 102, Section 192.383(d).

In its testimony, the Company stated that it has a significant concern regarding the impact of the new PHMSA requirements on customers exercising their option to request the installation of an EFV. Although the language of Section 192.383(d) states that "the operator's rate-setter determines how and to whom the costs of the requested EFVs are distributed," PHMSA's guidance suggests that individual customers could be charged directly for the cost of an EFV installation on an existing service. This raises a substantial concern for the Company because customers may perceive a safety need for an EFV installation as a result of the notification, but may not be willing or able to pay for the requested installation. The Company estimates that the cost to install an EFV on an existing service is approximately $3,000, depending upon the system and

---

[14] An EFV is a mechanical safety device installed on a natural gas service line between the street and the meter that shuts off the flow of gas in the event of a damaged service line. Such damage is typically caused by excavation activities near the service line.

the circumstances of the installation. The Company stated that it has been installing EFVs on new services for many years and that the installation costs have not been charged to the individual customer, but instead were collected through the Company's cost of service. Because of this, there could be an inequity involved with charging existing customers for EFV installations when new customers are not required to pay for the same installation. The Company also noted that the installation cost for a new service is approximately $150, which is much less than the $3,000 estimated cost of retrofitting an existing service with an EFV. LeBlanc/Sprague Dir. Test. at 34.

The Company stated that if an existing customer requests an EFV, it would install it in conjunction with other regularly scheduled work at the customer's location. If a customer requests an EFV installation on an earlier date, the customer may obtain the expedited installation at the customer's cost. The Company would file a term and condition to govern these charges.

The Company is proposing to recover the costs of non-expedited EFV installations for existing customers through TIRA 2. The Company's rationale for including EFVs in the TIRA is that they are significant safety improvements and non-revenue producing. The Company stated that it is subject to earnings attrition from non-revenue producing projects and EFVs are non-revenue producing capital projects that cause the Company's fixed costs such as depreciation, property taxes and return to rise faster than its revenues. The Company further states that it has not earned its allowed ROE since its acquisition in 2008, and if EFVs were to be excluded from the TIRA, it would only increase earnings erosion and hasten the need to file a future rate case. Chong Dir. Test. at 41.

The Company estimates that it has approximately 7,000 service lines that are eligible for the installation of an EFV. Further, the Company estimates that it will spend

$500,000 annually ($2.5 million total) between 2017 and 2021 installing EFVs at the request of customers. This is based on the Company's estimate that it will complete approximately 170 EFV installations per year for a total of 850 installations over the five-year timeframe. The Company further states that EFV installations will be unpredictable due to the installations being based on customer requests, therefore, the EFV expenditures should not be included in the Performance Standard (Section 4.06 of the TIRA) and the TIRA Performance Indices. LeBlanc/Sprague Dir. Test. at 35.

The OPA is opposed to including the cost of such installations in the Company's TIRA. According to OPA witness Mr. Morgan, inclusion of EFV costs is premature because cost recovery under an automatic rate adjustment mechanism such as the TIRA is generally reserved for: (1) significant costs that are mandated or costs that are beyond the control of the Company that have an impact on the Company's financial stability; or (2) material costs that are volatile or rising rapidly. In this instance, the Company has not demonstrated that the EFV costs meet either of these criteria. Further, according to the Company, no existing customer has requested an EFV to be installed on their service line, nor has the Company provided an analysis that shows that the annual installation costs in aggregate will have a significant impact on its financial results. Finally, Mr. Morgan states that although the installation of potentially 7,000 EFVs at $3,000 per installation sounds material, the fact is that at this point the cost to the Company is $0 annually. Morgan Dir. Test. at 25.

Staff shares the OPA's concerns regarding the inclusion of any costs associated with the installation of EFVs for existing customers in a TIRA extension, to the extent one is approved. The current TIRA, established in the Company's last rate case in Docket 2013-00133, allows for the recovery by the Company of prudently incurred investments in *Eligible Facilities* defined in the scope of work for (1) the Cast Iron

Replacement Program (CIRP), approved by the Commission in Docket No. 2008-151, (2) the replacement of bare steel and non-cathodically protected (unprotected) coated steel mains and services, and (3) the replacement of farm tap regulators, as described in Section 4.03 of Stipulation Exhibit 2. The installation of an EFV at the request of an existing customer is not related to any of the "Eligible Facilities" designated in 2013-00133. Further, the Staff does not agree with the Company's claim that the costs associated with installing EFVs for existing customers should be included in the TIRA because this is a significant safety improvement and is non-revenue producing. Simply because a cost has a safety benefit and is non-revenue producing does not mean that it should be included in an automatic rate adjustment mechanism such as the TIRA. The Company has substantial other costs that are related to safety and are non-revenue producing, such as the cost of moving facilities to accommodate excavation projects, that are not included in the TIRA. Finally, since the Company provided the EFV customer notice required by PHMSA regulations in April, 2017, it has not received a single customer request for an EFV. As more time passes from the time that the customer notice was provided, the likelihood that customers will request an EFV would seem to decrease.

For the reasons stated above, Staff recommends that, if a TIRA extension is approved, the Commission reject the Company's request to include costs related to the installation of EFVs. Furthermore, because there are no costs associated with EFVs for existing customers in the test year, nor any projection that would meet a "known and measurable" standard, no EFV costs for existing customers should be included in the Company's base revenue requirement.

3. Return on TIRA Rate Base

As noted above, the Company has proposed to increase the pre-tax rate of return on TIRA rate base from 11.0% to 11.83%. The proposed 11.83% rate of return is the pre-tax WACC proposed by the Company for its overall return in this proceeding. As detailed in Section II of the Bench Analysis, Staff recommends several changes to the Company's WACC calculation, including reducing the ROE from 10.30% to 9.50%, incorporating known and measurable changes to Northern's overall cost of long-term debt and incorporating a short-term debt component into the capital structure. These changes produce an overall pre-tax WACC of 10.65%, which would also be used as the TIRA rate of return.

Additionally, Staff recommends that the TIRA rate of return would be subject to annual adjustment to reflect applicable changes to the cost of long-term debt. Specifically, for purposes of calculating the TIRA revenue requirement each year, the Company would update its pre-tax WACC to reflect the overall weighted cost of long-term debt as of the end of the prior calendar year. Similarly, the Company would update its pre-tax WACC annually to reflect the average cost of short-term debt for the prior calendar year. Finally, any changes to the capital structure (common equity, long-term debt and short-term debt) or the ROE approved by the Commission in a rate case would be incorporated into the TIRA rate adjustment in the year following the year in which the Commission reached a decision in a rate case.

4. <u>Rate Cap</u>

The Company has proposed to increase the TIRA Rate Cap from 4% to 5%. According to Mr. Chong, given the "sharp increase in capital spending, a 4% rate cap is not sufficient" to allow it to recover the full amount of the TIRA revenue requirement. Chong Dir. Test. at 46. However, the Company's conclusion that a 4% Rate Cap is too low appears not to reflect either the fact that: (1) any base rate increase that would result from this proceeding; and (2) increased revenue associated with customer growth. When these factors are taken into account, there may be no need to increase the Rate Cap. In addition, for the reasons discussed by the OPA witness, increasing the Rate Cap would weaken any incentive the Company would otherwise have to control costs. For these reasons, the Staff recommends that, if the TIRA is extended, the Rate Cap remain at 4%.

D. Staff Position Regarding a TIRA Extension

The Staff supports an extension of the TIRA. However, any TIRA 2 should be designed to provide stronger incentives for cost management than were provided by TIRA 1. When it approved the CIRP, the Commission anticipated that a rate mechanism would be developed and implemented to govern recovery of CIRP costs. However, as noted by the Commission in the CIRP Order, any such rate mechanism must provide:

"(an) incentive for Northern to contain the overall costs of the project… (and) will also include disincentives for cost overruns." CIRP Order at 18.

As discussed above, the extent to which TIRA 1 effectively provided such incentives is unclear. Thus, Staff does not support a simple extension of the original TIRA, as proposed by the Company. Rather, any TIRA extension must include fundamental changes to its design. The Staff's proposed design features for TIRA 2, described below in Section IV(D)(3), are intended to remedy the weaknesses or flaws of TIRA 1 to ensure that the TIRA provides adequate incentives for cost control, as required by the CIRP Order.

Alternatively, if the Commission were to conclude that a TIRA would not be likely to provide sufficient incentives to manage project costs, the TIRA could be eliminated and the capital costs of the CIRP, UPS and FTR programs treated just like the Company's other capital investments. Although the TIRA programs are significant and, to a large degree, not revenue producing, the same can be said for other categories of the Company's capital investment. As shown in the Company's response to ODR-004-009, during the period 2013-2016, the CIRP investments represented less than half of the Company's non-revenue-producing investments. In terms of the Company's overall capital investments, during this same period the CIRP, UPS, and FTR investments represented about 25% of the Company's total capital spending. EXM-004-001. The Staff notes that one of the main reasons initially put forth in support of a TIRA was that the Company could not bear the financial burden of the TIRA investment without a rate adjustment mechanism. *Northern Utilities, Inc. d/b/a Unitil, Proposed Base Rate Increase and Rate Design Modification*, Docket No. 2013-00133, Order Approving Stipulation (December 27, 2013) at 9. Underlying this rationale is the premise that the investments required to be made under the TIRA would be significantly greater than the other capital investments that would be required of the Company. As noted above, this is not the case.

1. TIRA 2

The Staff's position on the O&M Offset, the inclusion of EFVs, the return of TIRA rate base, and the Rate Cap are set forth above. The remaining issues and additional design features proposed by Staff for TIRA 2 are addressed below.

2. Revised EVM

Absent clear evidence that the Company is managing the CIRP, UPS and FTR projects imprudently, or that it has artificially inflated the EVM, the Staff would accept the Company's revised EVM to measure cost and schedule performance during TIRA 2. Given that the revised EVM reflects the Company's substantial experience with the projects, no further revisions to the EVM should be made during TIRA 2.

3. Design Features for TIRA 2

Staff's support for a TIRA extension is premised on it being redesigned to eliminate what may have been weak, or perhaps even disincentives for the Company to manage project costs under TIRA 1. In addition, the design features of TIRA 2 should be modified as discussed below to provide stronger, affirmative incentives for cost control than was the case for TIRA 1. As noted above, these are both required by the CIRP Order.

i. Term

The Company has proposed to extend the TIRA for four years, which would relate to its investment in Calendar Years 2017-2020. Staff recommends that, if the TIRA is extended, it be extended through the scheduled end of the project(s), which is 2024. As noted above, the term of TIRA 1 was four years, and the expiration of that four-year term has provided an opportunity for the Company to rebase its EVM and to seek to use the rebased EVM for TIRA 2. A built-in "second (or third) bite at the EVM apple" may weaken the incentives for cost control and/or invite the type of "managing to the metrics" behavior that may have occurred under TIRA 1.[15] At this point, given that the Company has almost seven years of construction experience with the CIRP, and almost four years with the UPS and FTR projects, the scope and costs for the remainder of the project term should be well known and the need for further re-basing much less likely. If the TIRA were to be extended for only four years, the Company would have a weaker incentive to manage costs, given that it would have another opportunity to rebase the EVM, or at least request to do so. Additionally, a four-year term may provide another opportunity for the Company to "manage to the metrics" in the

[15] An example of a "managing to the metrics" opportunity is shown by Figures IV.1 and IV.4. In particular, compared to prior years, in 2016 the Company completed only a small amount of main installation work, and most of the 2016 work was done through insertion. The design of TIRA 1 provided an opportunity for the project schedule for 2016 to be "managed" to avoid relatively higher cost components, given how close to 1.0 the CPI was in the prior year and given that 2016 was the last year of TIRA 1.

manner described in footnote 5. Finally, for these same reasons, TIRA 2 should continue to govern recovery of CIRP, UPS and FTR costs even if the Company files a base rate case before the end of the proposed term.

ii. Metrics and Incentives

The same metrics, i.e., CPI and SPI, should be used to measure performance. However, Staff suggests two changes to how the TIRA would operate with respect to these metrics. First, as with TIRA 1, if either of the metrics (on a cumulative basis starting with 2017) is less than 1.0, there would be no TIRA adjustment that year. However, in contrast to the TIRA 1, which would have been suspended pending a more thorough review if either metric was less than 1.0, Staff suggests that the TIRA remain in place. If the Company brings the metrics back up to 1.0 or greater in the following year, the rate adjustment would occur at that point, and the Company could recover the entire revenue requirement amount attributable to both years.[16] [17] This potential lag would provide an incentive for the Company to keep the program at or under budget and on or ahead of schedule at all times. In addition, having the TIRA remain in place if an index drops below 1.0, provides an incentive for the Company to manage the program to bring the indices back to 1.0.

Second, Staff suggests that the ROE for the CIRP, UPS and FTR investment be set as a function of the Cost Performance Index. The ROE would be tied to the CPI and not to the SPI because Staff views the project schedule, which has been approved by the Commission, to be appropriate. As such, a financial incentive (funded by

---

[16] In such a case, the applicable Rate Cap would be 8%.

[17] The existing methodology calculates the rate adjustment as the difference in revenue requirements between two years, albeit sequential years. However, it seems like this same methodology would also work if the difference was between two years that were not sequential

ratepayers) to accelerate the schedule would not appear to be in ratepayers' interest. In addition, based on the Company's performance to date, it has been able to keep the project comfortably ahead of schedule.

The ROE incentive mechanism proposed by Staff would work as follows. If the CPI was equal to 1.0, the ROE would be equal to the Staff recommended ROE for the Company's rate base in total, which is 9.5%. The ROE would then be adjusted based on a CPI range of 1.0 to 1.3, the upper end of which reflects Actual Costs being about 25% below the Earned Value on a cumulative basis in a given year. The upper end of the ROE range would be 300 basis points above the Staff recommended ROE, or 12.5%.

The Staff's proposed ROE incentive is illustrated below in Figure IV.6.

Figure IV.6

	Low	High	Delta
CPI Range	1.000	1.300	0.300
ROE Range	9.5%	12.5%	3.0%

Change in ROE per 0.1 point change in CPI *1.00%*

CPI	ROE	
0.950	#N/A	*No rate adjustment - CPI < 1.0*
1.000	9.50%	
1.050	10.00%	
1.103	10.53%	
1.210	11.60%	
1.245	11.95%	
1.265	12.15%	
1.300	12.50%	

iii. Earnings Sharing

Staff recommends continuing to include an overall earnings sharing mechanism to ensure that the TIRA does not result in excess profits for the Company. The existing ESM allows the Company to retain all earnings that result in a ROE up to and including 10%. Any earnings that result in an ROE greater 10% and up to and including 11% are shared 50/50 with customers. For any year in which the ROE is greater than 11%, the earnings returned to customers are 50% of all amounts from 10% to 11% and 100% of all amounts above 11%. The ROE is calculated annually based on the calculation of the Return on Common Equity Subject to MPUC Jurisdiction as submitted in the Company's Annual Report, with modifications to include weather normalization and unbilled revenue.

Going forward, Staff recommends including an ESM through the term of TIRA 2 with several significant modifications. First, the earnings sharing trigger points would be adjusted to reflect the ROE determined in this case. Based on the recommended ROE of 9.50%, the ESM mechanism would permit the Company to retain all earnings up to and including an ROE of 9.50%. Any earnings that result in an ROE greater than 9.50% and up to and including 10.50% would be shared 50/50 with customers. For any year in which the ROE is greater than 10.50%, the earnings returned to customers would be 50% of all amounts from 9.50% to 10.50% and 100% of all amounts above 10.50%. The mechanism for implementing the earnings sharing provisions under TIRA 2 would remain the same as in TIRA 1.

Additionally, if the Company achieves a Cost Performance Index such that an ROE incentive as described above were triggered, the ESM should be structured so that the ROE incentive is retained by the Company and not "taken back" by operation of the ESM calculations. Staff proposes that the annual TIRA adjustment filing include a specific adjustment to reflect the impact on the Company's net income and ROE calculation used to determine whether the ESM would be triggered. As illustrated below, in any year in which an ROE incentive is allowed, the Company would adjust its Net Income from Commission jurisdictional revenues downward to account for the after-tax net income associated with the ROE incentive. This adjusted Net Income would then be used to calculate the ROE to determine whether the ESM is triggered and to calculate the amount to be returned to ratepayers.

An illustration of this adjustment in shown in Figure IV.7 below.

Figure IV.7

Line	Item		20XX	Explanation
1	Incremental TIRA Revenue Requirement @ Incentive ROE of 10%	$	1,300,000	For illustration purposes only
2	Incremental TIRA Revenue Requirement @ Base ROE of 9.5%	$	500,000	For illustration purposes only
3	Incremental TIRA Revenue Requirement Attributable to Incentive ROE	$	800,000	Line 1 - Line 2
4	Taxes	$	(319,120)	-Line 3 * 0.3989 Federal and State Tax Rate
5	Net Income Effect of Incentive ROE	$	480,880	Line 3 + Line 4
	Weather-Normalized Return on Equity Calculation			
6	Total Net Income from Commission Jurisdiction		$8,000,000	ME PUC Annual Report
7	Adjustments to Weather-Normalize:			
8	Weather Normalization		$900,000	Adjust revenue for normal weather
9	Unbilled Revenue		($125,000)	Remove unbilled revenue
10	Tax Effect		($309,148)	-(Line 8 + 9) * 0.3989 Federal and State Tax Rate
11	Total Weather-Normalized Net Income From Commission Jurisdiction		$8,465,853	Line 6 + 8 + 9 + 10
12	Total Weather-Normalized Net Income From Commission Jurisdiction, Excluding Incentive ROE Revenue		$7,984,973	Line 11 - Line 5
13	Total Common Equity for Investments Subject to Commission Jurisdiction		$85,000,000	ME PUC Annual Report
14	Weather-Normalized Return on Equity		10.0%	Line 11 / 13
15	Weather-Normalized Return on Equity, Excluding Incentive ROE Revenue		9.4%	Line 12 / 13

V. RATE DESIGN

A. Company's Proposal

The Company's proposed revenue allocation and rate design are based on the testimony of its witnesses Ms. Gajewski and Mr. Normand, both of whom are consultants with Management Applications Consulting (MAC). The Gajewski/Normand testimony and recommendations are based on two cost of service studies: an accounting, or embedded, cost of service study, and a marginal cost of service study.

The Gajewski/Normand testimony includes exhibits that contain hundreds of pages of detailed cost of service study output and workpapers.

There appear to be two major conclusions drawn by the witnesses from the results of the studies. First, that customers in the residential rate classes (R1 and R2) are currently subsidized by other customers and, second, that most of the costs to provide distribution service are fixed and, thus, should be recovered through fixed charges rather than volumetric charges. However, in recognition of other considerations when designing rates, such as rate stability, the witnesses apply their judgement to the study results and recommend class revenue allocations and rate design changes that move in the direction indicated by their studies (at least, in some cases), but not to the full extent indicated. For example, the witnesses propose capping the overall revenue percent increase to the residential classes at 1.25 times the overall Company average, even though they contend that their studies support a larger increase.

B. Revenue Allocation

Figure V.1 below shows the Company's recommended class revenue allocation. Note that this Figure is based on the Company's initial filing, and does not include the additional revenue requirement increase of $677,000 proposed in the supplemental testimony of Mr. Chong.

Figure V.1

Increase by Customer Class				
Class	**Existing Revenue [1]**	**Proposed Revenue [2]**	**$ Increase**	**% Increase**
Residential Heating (R-2)	11,493,243	13,485,687	1,992,444	17.34%
Residential Non-Heating (R-1)	1,298,049	1,523,127	225,078	17.34%
Low Annual, High Winter Use (G-40/T-40)	9,183,658	10,295,549	1,111,891	12.11%
Low Annual, Low Winter Use (G-50/T-50)	978,814	1,100,402	121,588	12.42%
Medium Annual, High Winter Use (G-41/T-41)	8,618,375	9,687,071	1,068,696	12.40%
Medium Annual, Low Winter Use (G-51/T-51)	1,763,399	1,982,593	219,194	12.43%
High Annual, High Winter Use (G-42/T-42)	5,390,183	6,070,902	680,719	12.63%
High Annual, Low Winter Use (G-52/T-52)	4,202,540	4,735,667	533,127	12.69%
[1] Exhibit DLG/PMN-1G-8, page 2, coulmn R				
[2] Exhibit DLG/PMN-1G-8, page 6, coulmn AE				

Figure V.2 below shows the average revenue per ccf by rate class at both existing and the Company's proposed revenue levels, again without the additional amount presented in the Chong Supplemental Testimony.

Figure V.2

Cost per CCF					
Class	**Weather Normalized CCFs [1]**	**Existing Revenue [2]**	**Proposed Revenue [3]**	**Cost per CCF @ Current Rates**	**Cost per CCF @ Proposed Rates**
Residential Heating (R-2)	14,459,686	$ 11,493,243	$ 13,485,687	$ 0.79	$ 0.93
Residential Non-Heating (R-1)	623,674	$ 1,298,049	$ 1,523,127	$ 2.08	$ 2.44
Low Annual, High Winter Use (G-40/T-40)	14,999,927	$ 9,183,658	$ 10,295,549	$ 0.61	$ 0.69
Low Annual, Low Winter Use (G-50/T-50)	1,406,384	$ 978,814	$ 1,100,402	$ 0.70	$ 0.78
Medium Annual, High Winter Use (G-41/T-41)	22,514,299	$ 8,618,375	$ 9,687,071	$ 0.38	$ 0.43
Medium Annual, Low Winter Use (G-51/T-51)	4,944,842	$ 1,763,399	$ 1,982,593	$ 0.36	$ 0.40
High Annual, High Winter Use (G-42/T-42)	21,458,618	$ 5,390,183	$ 6,070,902	$ 0.25	$ 0.28
High Annual, Low Winter Use (G-52/T-52)	19,015,815	$ 4,202,540	$ 4,735,667	$ 0.22	$ 0.25
[1] Exhibit DLG/PMN-1G-8, page 1, column F					
[2] Exhibit DLG/PMN-1G-8, page 2, coulmn R					
[3] Exhibit DLG/PMN-1G-8, page 6, coulmn AE					

In Staff's view, if the Company's overall requested revenue requirement increase, or an increase close to that, were to be granted, an additional increase of 1.25 times the average overall increase for the residential classes would be unduly burdensome. With the additional revenue requirement amount proposed by Mr. Chong in his Supplemental

Testimony, the Company's revenue allocation proposal would result in an increase of almost 20% on average for residential customers. (As discussed below, for some residential customers, the increase would be even greater than 20%.) The level of this increase should also be viewed in the context of the series of TIRA increases over the past four years which, in the aggregate increased the Company's distribution rates by 13.8%. If the TIRA is extended, additional rate increases for the next several years can also be predicted.

The Staff is not filing an alternative cost of service study in this case, nor has the Staff engaged in a sufficiently in-depth review of the Company's studies to either challenge them or support them. This is, in large part, based on Staff's view that certain conclusions supported by the Company's cost of service studies, such as the fixed nature of distribution system costs, are not disputed. In addition, other conclusions supported by the studies, such as revenue allocation, involve a substantial degree of judgement and consideration of other factors, such as rate stability and the overall level of the revenue requirement increase resulting from this case, as well as the level of recent and future rate increases resulting from the TIRA should play a substantial role in determining any rate design changes. Staff's final recommendation on revenue allocation will be made in the Examiner's Report, at which time Staff's recommendation on the overall revenue requirement increase will also be presented.

C. <u>Intra-Class Rate Design</u>

Figure V.3 below illustrates the Company's proposed changes to rate elements for a sample of its rate classes. (The rate elements for all classes are presented in Exhibit DLG/PMN-1G-9.) As noted above, these proposed rate elements do not include the additional revenue requirement increase presented in Mr. Chong's Supplemental Testimony. As with revenue allocation, the Company's proposed intra-class rate design was informed by the cost of service studies, but, ultimately, appears to have been more a matter of judgement. Gajewski/Normand Testimony at 34.

Figure V.3

Rate Increase			
Rate Component	**Current Rate**	**Proposed Rate**	**% Increase**
Residential Heating (R2)			
Customer Charge	$ 25.11	$ 28.85	14.89%
Distribution Charge - First 40 ccf	$ 0.4599	$ 0.5244	14.02%
Distribution Charge - Excess 40 ccf	$ 0.3520	$ 0.4166	18.35%
General Service - Low Annual, High Winter use (G40)			
Customer Charge	$ 59.63	$ 68.50	14.88%
Distribution Charge - First 70 ccf	$ 0.3070	$ 0.3331	8.50%
Distribution Charge - Excess 70 ccf	$ 0.2834	$ 0.3095	9.21%
General Service - High Annual, High Winter use (G42) - Winter Rate			
Customer Charge	$ 1,004.76	$ 1,150.00	14.46%
Distribution Charge - First 18,000 ccf	$ 0.2712	$ 0.2924	7.82%
Distribution Charge - Excess 18,000 ccf	$ 0.2361	$ 0.2573	8.98%
General Service - High Annual, High Winter use (G42) - Summer Rate			
Customer Charge	$ 1,004.76	$ 1,150.00	14.46%
Distribution Charge - First 6,000 ccf	$ 0.2260	$ 0.2472	9.38%
Distribution Charge - Excess 6,000 ccf	$ 0.1888	$ 0.2100	11.23%

Source: Exhibit DLG/PMN-1G-9

At this point, Staff finds little support in the record for the variances in percent changes in rate components shown above. For example, it is not clear why the rates for the “tail block”, should increase by more than the rates for the “initial block”. This appears to have been done to maintain a constant $/ccf differential between the blocks, but there is no explanation for why this is a necessary or desirable outcome. The Company’s approach results in higher-than-average bill increases for higher-than-average use customers. For example, for high-use residential heating customers, bills would increase by more than 20% as a result of the Company’s proposal. Moreover, this approach, i.e., higher increases for higher-use customers, does not seem to be consistent with the witnesses’ testimony that the costs of providing distribution service are largely fixed. Additionally, although not proposed as a change in this proceeding, rates for some classes vary by season (winter vs. summer), and for other classes the rates are the same in each season. Staff assumes this is a result of a decision in a prior proceeding; however, it is an example of the imprecise nature of the Company's rate design.

With respect to the Company's testimony that the costs of providing distribution service are largely fixed and do not vary with usage, the Staff generally agrees. Thus, Staff would support relatively higher increases to the customer charges. Again, Staff's final recommendation on intra-class rate design will be made in the Examiner's Report, at which time Staff's recommendation on the overall revenue requirement increase and class revenue allocation will also be presented.

Dated at Hallowell, Maine, this 6th day of October, 2017.

October 6, 2017

Respectfully submitted,

Charles Cohen
Hearing Examiner

Leslie Raber
Hearing Examiner

On Behalf of Advisory Staff:

Faith Huntington
Derek Davidson
Christine Cook
Lucretia Smith
Sally Merritt
Matthew Rolnick

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2017-00198

June 28, 2018

EMERA MAINE
Request for Approval of
Proposed Rate Increase

ORDER

VANNOY, Chairman; WILLIAMSON and DAVIS, Commissioners

I. SUMMARY

By this Order, the Commission rejects Emera Maine's proposed increase in its distribution delivery rates of $10,042,990 or 12% as filed on October 2, 2017 and modified by its Rebuttal Testimony of February 8, 2018. In its place, the Commission authorizes the Company to increase its delivery rates by $4,453,645 or 5.32% as of July 1, 2018. The Commission's decision is based on a cost of equity of 9.35%. The computations supporting this decision are provided in Exhibit 1 to this Order. This rate increase shall be implemented through the "across the board" methodology based on the billing determinants set forth in the Company's sales and revenue forecasts and rate calculations testimony of October 2, 2017.

II. BACKGROUND

On August 2, 2017, the Company filed a letter with the Commission, pursuant to 35-A M.R.S. § 307 and Chapter 120, § 6 of the Commission's Rules, notifying the Commission of the Company's intent to file a proposed rate increase. The Company stated that it expected to request a $10.1 million, or 12%, increase in its overall distribution revenues, based on a return on equity of approximately 9.5%. The Company also stated that it expected to file its proposal on or about October 2, 2017.

On September 13, 2017, the Commission provided public notice of the Company's intent to file a proposed rate increase. The Commission also solicited interventions in the proceeding and scheduled an initial case conference. The Commission received timely intervention petitions from the OPA and the Aroostook Energy Association, both of which were granted by the Hearing Examiners. The Commission also received one late-filed intervention petition from the Town of Millinocket. After receiving no objections to the Town's intervention, the Hearing Examiners granted the Town's petition with the caveat that the Town take the case as it found it.

On October 2, 2017, the Company submitted its direct testimony in support of its request to raise distribution rates by approximately 12% or $10 million. The Company broke down the overall increase as follows:

Figure II.1[1]

Description	Amount
Investment in capital and associated costs	$3.9
Reliability (Vegetation Mgt, Danger Trees, Storm Response & Engineering Resources)	2.0
Customer Experience / Service Levels	1.2
Return to Appropriate ROE (9.5%)	1.1
Roll off of amortizations of Retiree Medical Prior Service Cost Gains	1.9
Other	0.7
	10.8
Increased revenues from higher sales vs 2016 rate case	(0.8)
Total	$10.0

In support of its rate increase request, Emera stated that:

1. The increase is necessary for Emera Maine to provide safe, reasonable and adequate facilities and service. This will include specifically addressing the areas where the Company's facilities or service was found to be deficient by the MPUC in its 2016 distribution rate proceeding Order;

2. The Company is operating as efficiently as possible and is utilizing sound management practices; and

3. The increase is required by the Company in order to attract necessary capital on just and reasonable terms.

The Company further noted its expectation that the capital and operating investments would, over time, result in fewer outages and less hours without power in normal and severe weather conditions; that the increased resources of the "Customer Experience Functions" would ensure that regular service levels are consistently meeting the expectations of the Company's customers and regulators today and into the future; and, finally, that Emera has responded appropriately and successfully to the Commission's concerns set forth in Emera's most recent rate case which were the basis for the Commission's 50 basis point ROE reduction. *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket 2015-00360, Order Part II (Dec. 22, 2016) (*2015-00360*). Therefore, the Company argued that the 50-basis point reduction should be removed.

In support of its position that its rates are, and will continue to be, just and reasonable, the Company stated that even with the proposed increase in this filing, real distribution rates would be approximately at the same level they were fifteen years ago. In terms of overall delivery price (transmission, distribution, stranded cost and conservation), the Company stated that real prices are less than they were fifteen years ago, and assuming today's supply costs, overall electricity bills will also be lower than

[1] Richardson Pref. Dir. Test. at 6.

they were fifteen years prior. The Company declined the Commission's invitation to consider presenting a rate plan that could provide incentives for improved performance and enhanced earnings, along with its rate increase proposal in this case. The Company stated that it needed to advance its thinking in several areas before it was willing to propose a multi-year plan. The Company noted that it will continue to advance its thinking in these areas, and may choose to file such a proposal in a future case.

After an initial round of discovery conducted on the Company's case, the Hearing Examiners convened a technical conference on November 30, 2017 and December 1, 2017. During the technical conference, Commission Staff and intervenors were provided an opportunity to conduct live discovery on the Company through cross-examination.

On December 21, 2017, Commission Staff issued a Bench Analysis setting forth the Staff's analysis of the Company's case.[2] With regard to customer service, Staff recognized that in several areas the Company has made strides toward meeting the performance standards set forth in the Commission's Order in *2015-00360*. In other instances, however, Staff noted that the Company's management practices continued to be inefficient and below reasonable expectations, and in Staff's view, warranted setting the allowed Return on Equity (ROE) in this case at 9.00%, which is towards the lower end of the range of allowed reasonable returns.

Staff further noted that the Company did not file an alternative rate plan (ARP) proposal as part of its rate increase request in this proceeding. Given the compressed schedule in this case and scope of this case, Staff did not propose a rate plan as part of the Bench Analysis. Staff recommended, however, that after this case, the Commission initiate a follow-on proceeding to establish a rate plan for Emera Maine to take effect on July 1, 2019. In addition, Staff estimated that the recently enacted federal Tax Cuts and Jobs Act (TCJA) would reduce the Company's revenue requirement by approximately $4 million. Staff requested that the Company, in its rebuttal testimony, update its weighted average cost of capital (WACC) to reflect the changes necessitated by the TCJA.[3]

Also on December 21, 2017, the OPA filed its testimony in this matter. In its testimony, the OPA provided the level of revenue that it believed the Commission should authorize the Company to collect from its ratepayers. After analyzing the Company's filings and responses to discovery, the OPA recommended that the Commission find a revenue deficiency of approximately $6.3 million, as compared to the approximately $10 million deficiency proposed by the Company. The OPA also recommended the Commission set an overall rate of return of 7%, as opposed to the

---

[2] The Bench Analysis contained typographical errors with regard to some dollar amounts cited by Staff. Staff issued a Corrected Bench Analysis (Corr. B.A.) on January 12, 2018 which remedied these errors. For ease of reference and consistency purposes, cites to the Bench Analysis are to the Corr. B.A.

[3] Staff also requested, by Procedural Order dated January 11, 2018, that the Company, as a part of its rebuttal case, address the issue of the issuance of an accounting order, pursuant to 35-A M.R.S. §501, to establish a regulatory liability which defers for future flow-through to ratepayers the impact of the tax changes effective January 1, 2018.

Company's proposed 7.24%. The OPA recommended an ROE of 9%, as opposed to the Company's 9.5%, to reflect the management efficiency adjustment imposed by the Commission in *2015-00360*.

On February 8, 2018, the Company filed its rebuttal testimony. As with its initial testimony, the Company submitted testimony from subject matter specific panels. First, the Company's "Policy Panel" responded to the Staff's view, as expressed in the Bench Analysis, that Emera has been, and continues to be, poorly managed. The Company argued that the Company had followed the Commission's direction from *2015-00360* and implemented all of the most important changes recommended by the Commission. As a result, according to the Company, its customer service performance has improved dramatically and to the benefit of its customers. The Company also disagreed with the contention that the issues described by Staff in the Bench Analysis constitute poor management and also disagreed with Staff's proposal that it should be required to develop an ARP, arguing that the Company is simply not prepared at this time to engage in this endeavor.

The Company's "Revenue Requirements" panel revised the Company's original revenue requirement, discussed the specific adjustments to the revenue requirement proposed by Staff and by the OPA, and discussed the impact of the TCJA. In the Revenue Requirements Testimony, the Company proposed decreasing its original $93.8 million revenue requirement by $6.3 million due to the savings accruing to the Company as a result of the TCJA. The Company also proposed amortizing the costs of the October 2017 windstorm over a five-year period which would add $1.46 million to its original revenue requirement. The combination of these two factors would result in a net decrease in the Company's original revenue requirement proposal of approximately $4.86 million.

On March 13, 2018, the Company filed Supplemental Testimony regarding the impact of the TCJA. In its Supplemental Testimony, the Company stated that it could not, at this time, determine the precise savings that will result from the TCJA. Notwithstanding the uncertainty regarding the amount of savings, the Company proposed that it use the savings to offset other recent costs, in particular the costs associated with the October 30, 2017 wind storm. Savings not appropriated to storm costs would, under the Company's proposal, be used to offset other existing Company amortizations including inflation, retiree medical savings, and investments in automated metering infrastructure (AMI).

On April 4, 2018, Staff filed a Reply Bench Analysis. In the Reply Bench Analysis, Staff provided its view of how the effects of the TCJA should be treated in this case; updated its analysis regarding cost of capital and the Company's concerns with that analysis, including the proxy group utilized by Staff; discussed the Company's concerns with regard to Staff position on rate base; and provided further discussion regarding Staff's expense adjustments. Also on April 4, 2018, the OPA filed its surrebuttal testimony. In its surrebuttal, the OPA addressed issues raised by the Company in the Revenue Requirements rebuttal testimonies. The OPA also provided its analysis of the impact of the TCJA.

On April 19, 2018, the Company filed Supplemental Testimony regarding adjustments to the Company's proposed revenue requirement. In this Supplemental Testimony, the Company proposed a $404,922 reduction in its income tax expense. The Company also explained in this testimony that it had inadvertently credited approximately $13.5 million in deferred income taxes to rate base twice, resulting in an improper decrease in the total amount of net Accumulated Deferred Income Tax Liability allocable to distribution from $81,562,767 to $68,010,442. The Company, therefore, proposed to correct this $13.5 million error.

On May 1, 2018, the Commission conduced Public Witness Hearings in this matter to allow customers of Emera Maine to directly address the Commission and share their views regarding the Company's request for an increase in rates. The Commission conducted the Public Witness Hearings simultaneously in Orono, Presque Isle, and Machias. One Commissioner was physically present in each location and the locations were linked via live audio and video; participants in each of the locations could see, hear, and interact with the other locations in real-time. The Commission received testimony from more than twenty Emera Maine customers at the hearings.

The Commission held an evidentiary hearing in this matter on May 3, 2018. At the hearing, the Hearing Examiners admitted evidence into the record proffered by the parties; parties were provided with an opportunity to examine witness who provided testimony in this matter; and the Company was provided an opportunity to examine Staff regarding its Bench Analysis and Reply Bench Analysis.

On May 23, 2018, both the Company and the OPA filed their post-hearing briefs. The Hearing Examiners issued their Examiners' Report on June 8, 2018. On June 15, 2018, Emera filed exceptions to the Examiners' Report, and the OPA filed a letter stating that it had no exceptions to the Examiners' Report and urged the Commission to adopt the Report in full.

III. REVENUE REQUIREMENT ISSUES

A. Rate Base

1. Gain on the Sale of Lower Main Street Property

a. Positions Before the Commission

Emera entered into a purchase and sale agreement for the sale of the Lower Main Street Property and expects this sale to close in Quarter 2 of 2018. Chahley/ Davoren/Therrien Dir. Test. at 30. Emera states that the pending sale will not result in a gain on the sale of the building and that the Company has reflected the pending gain on the sale of the land in a below-the-line account (Account 421.1) in its rate filing, consistent with FERC accounting rules. Emera allocated the net sales proceeds between the land and the depreciable assets using the tax assessed value. The proceeds allocated to land resulted in a gain when compared to the total book value of the land. The proceeds allocated to the depreciable assets were not greater than the book value of the assets. Emera estimates the gain on the sale of the land to be

$146,469.[4] Emera retired the Lower Main Street Property and the original cost was offset against accumulated depreciation. Emera's filing indicates that Emera incurred $447,615 of removal costs related to the Lower Main Street facility. Consistent with normal utility accounting practice, Emera charged the full cost of removal against the accumulated depreciation balance. Chalhey/Davoren/Therrien Dir. Test. at Exh. RR-25.

In the Bench Analysis, Staff noted that while Emera's accounting reflected the requirements of the FERC Uniform System of Accounts, that accounting resulted in the gain on the sale of the land associated with the Lower Main Street assets being retained by Emera rather than flowing to the benefit of ratepayers while at the same time resulting in ratepayers incurring the full cost of removal. Staff stated that it was unlikely that the cost of removal was entirely related to the building given that the purchase and sale agreement required the completion of work on the land as well as the building and that the cost of removal should not be borne entirely by the ratepayers. Corr. B.A. at 87.

Staff further noted that the Commission has found that where ratepayers bear the risk of loss or shoulder the burdens associated with utility investment, ratepayers are entitled to the gain on the investment, citing *Central Maine Power Company, Annual Price Change Pursuant to the Alternative Rate Plan,* Docket No. 1999-00155, Order on CMP's Motion for Reconsideration (Jan. 20, 2000) (*CMP, Docket No. 1999-00155*). The Staff continued that, in this instance, ratepayers assumed the depreciation costs associated with the Lower Main Street property and bore the risk of sale at a loss. Although for property tax purposes the land and buildings may be separable, ratepayers have also provided investors with a return on the total investment throughout the period that the property was owned by Emera. Staff recommended that, for ratemaking purposes, the gain Emera attributed to the land should be used to reduce the removal costs associated with the retirement and sale of the Lower Main Street property. Corr. B.A. at 88.

The OPA in its initial testimony disagreed with Emera's proposed accounting and recommended an adjustment to reflect a 3-year amortization of the gain on the property to flow back the gain to ratepayers. Morgan Dir. Test. at 14. The OPA states in its Brief that Emera's treatment of the gain is contrary to Commission precedent which requires that ratepayers are entitled to the benefit of the gain. OPA Brief at 22. The OPA argues that the gain on the sale of the property should be passed on to ratepayers and recommends that it be accomplished consistent with the treatment outlined in the Bench Analysis, as an offset to the Company's cost of removal related to the Lower Main Street property. OPA Brief at 23 – 24.

Emera disagrees with the conclusions reached by the Staff and the OPA. Emera notes that it expects to record a gain on the sale of its Lower Main Street property of $146,569 when the sale of that property is completed. It states that the gain is associated with the sale of the land rather than the building located on the property. Emera Brief at 21. Emera notes that land is a non-depreciable asset and consequently, Emera's shareholders earned only a return on the investment in Lower Main Street land

---

[4] In its initial filing, Emera calculated a gain of $249,923 but revised the gain to $146,469 in its rebuttal after noting an error in its calculations. Emera Rebuttal at 8.

while it was in service to customers and did not earn a return of that investment. Emera further argues that shareholders bore the risk of loss associated with the sale of the land. Emera states that the land and building required environmental remediation as a result of its use as a vehicle depot while used to serve customers and it incurred $452,121 in removal costs related to the Lower Main Street facility which it charged against the accumulated depreciation balance for the building. Because the restoration costs result from Emera's service to its customers, these costs should be fully recoverable in rates. Emera states that if the Commission were to use the gain associated with the sale of the land to offset the restoration costs, that would effectively transfer the responsibility for the costs of providing service from customers to shareholders. Emera Brief at 21.

Emera also argues that the appropriate precedent and principles to apply in this circumstance are those set forth by the Maine Supreme Judicial Court in its decision in *Maine Water Company v. Public Utilities Commission*, 482 A.2d 443 (Me. 1984) (*Maine Water Company).* Emera states that according to the *Maine Water Company* decision, the gain on the sale of non-depreciable property is generally not allocated to ratepayers because "customers pay for service, not the property used to render it," and that by paying for service, customers do not acquire any interest, either legal or equitable, in the property. Emera argues that its customers bore no cost of depreciation associated with the Lower Main Street land because land is not depreciable and that the customers bore no risk of loss associated with the sale of the land. Emera argues that Staff has not suggested in this case that had Emera sold the land at a loss rather than a gain, that the loss would now be recoverable from ratepayers. *Id.* at 22 – 23.

Emera concludes that the Commission should find that the gain associated with the sale of the land is properly allocated to shareholders rather than ratepayers. Alternatively, the Commission should find that the shareholders are entitled to at least 10% of the gain associated with the sale. *Id* at 24.

b. <u>Decision</u>

In *CMP, Docket No. 1999-00155*, *supra.* at 5, the Commission found that past Commission decisions indicated that ratepayers, and not shareholders, bear the risk of loss on prudently incurred utility investments. The Commission, therefore, rejected CMP's argument in that case that ratepayers are like tenants in that they do not bear any risk of loss on non-depreciable property and, therefore, are not entitled to any gain on such property. In reaching this conclusion, the Commission found that the language contained in the Law Court's *Maine Water, supra.* decision concerning the gain on the sale of non-depreciable property, such as land, was dicta and not controlling. The Commission stated:

> The dicta in *Maine Water,* distinguishing depreciable and non-depreciable property, is difficult to reconcile with the practical application of utility rate regulation. The Law Court theorized that ratepayers are not entitled to the gain on the sale of non-depreciable utility property because they do not bear the risk of loss on such property. As discussed below, we conclude that ratepayers *do* bear the risk of loss on utility investments (absent a finding of imprudence) whether such investments are in depreciable or

non-depreciable assets.

CMP, Docket No. 1999-00155 at 8. The Commission recently reaffirmed its view that gains and losses from the sale of utility property applied to both depreciable and non-depreciable property, in *Northern Utilities Inc. d/b/a Unitil, Request for Approval of Rate Change Pursuant to Section 307,* Docket No. 2017-00065, (Feb. 28, 2018).

Because ratepayers bear the risk of loss on depreciable as well as non-depreciable property absent a finding of imprudence, the Commission has generally not distinguished between the two in allocating the gain to ratepayers. *Id.* at 10. The Commission finds that the sale of the Lower Main Street facility should be treated similarly. When all of proceeds and costs, including removal and restoration costs, are considered, there was, in fact, no gain from the transaction. In its exceptions, Emera argues that to the extent the Commission rules against the Company on this issue, that the "gain" should be allocated between transmission and distribution before it is flowed through to the benefit of distribution ratepayers. Emera Exceptions at 9. The Commission agrees with the Company here. Thus, the $146,469 that it considered a "gain" from the land sale will be allocated between transmission and distribution using the appropriate allocator and the distribution portion of the gain shall be applied to offset the removal costs associated with the transaction recorded in Account 108.

2. <u>2018 Plant Additions</u>

a. <u>Positions Before the Commission</u>

In the Bench Analysis, Staff noted that Emera had estimated additions of $34,516,075 for calendar year 2018 which was approximately an 18% increase over the additions estimated in 2017. Staff noted that the Base Additions increased by approximately 4.4% while Major Additions increased by 217%. Corr. B.A. at 85. Staff recommended that the Base Additions should be increased by using the same inflation adjustment that Emera had used elsewhere in its filing and, therefore, should not be more that 2.05%. *Id.* Staff also noted it was not confident that all of the Major Additions would be put into service during 2018 and requested that Emera provide a status of each of the projects and support showing that the projects would go into service in its rebuttal testimony. *Id*.

In its Revenue Requirement Rebuttal Testimony, Emera noted its disagreement with Staff's position. Chahley/Davoren/Therrien Reb. Test. at 4. The Company reasoned that base capital spending should not be limited to an inflation cap since the Company's 2018 forecasted capital spending is based upon the Company's assessment of the capital additions and the replacement of deteriorated plant that will be required in 2018 to continue to provide safe, adequate, and reliable service to Emera's customers. *Id.* at 5. Thus, such spending is not simply a reflection of an inflationary adjustment. Emera also notes that its projected base capital additions allocated to distribution in 2018 is $28,769,529, which is less than the 2017 actual base capital additions spending allocated to distribution of $29,527,741 and is only 1% greater than 2016 actual base capital additions. *Id*. at 5. In its Reliability and Distribution Operations Rebuttal Testimony Emera provided support that its Major Plant Additions included in its 2018 Plant Additions would be placed into service during the rate effective year. Belliveau/Ravin/Richardson/Holyoke Reb. Test. at 17.

The OPA initially recommended that $1.3 million related to the New Sweden sub-Purchase Land be removed from rate base as land would not be considered used and useful until the construction of the substation is completed and in service. Morgan Dir. Test. at 11. In its Surrebuttal Testimony, the OPA withdrew its recommendation based upon the clarification that the Company had included in its rebuttal testimony. Morgan Sur. Test. at 14. The OPA did not include any discussion of the 2018 Capital Additions in its Brief.

b. Decision

The Commission agrees that there are factors separate from inflation that affect the level of plant additions. In looking at past distribution spending levels, 2018 projections appear reasonable and, therefore, the Commission accepts the 2018 Plant Base Additions as proposed by Emera. The Commission also allows the 2018 Major Additions not addressed elsewhere in rate base as proposed by Emera.

3. 2019 Plant Additions

a. Positions Before the Commision

Emera calculated the amount of 2019 capital additions included in rate base as 50% of its overall planned base capital additions for that year, resulting in capital additions of $14,744,794 being reflected in the distribution rate base. Chahley/Davoren/Therrien Reb. Test. at 5 – 7. This assumes that the additions to rate base are done ratably over the period January through June. Emera states that it used the timing of its capital spending as a proxy for when plant would be put into service.

In the Bench Analysis, Staff noted that while Emera's filing reflected that additions were placed into service ratably over a 12-month period, Emera's response to ODR-001-003 showed the monthly pattern of when capital additions are closed to rate base and indicated that Emera's additions have not occurred ratably over each month. In none of the completed years shown in that response were more than 37% of the total year's additions added to rate base during the first six months of the year. Therefore, Staff concluded that Emera's assumption that 50% of the plant additions would occur during the first half of the year was not historically accurate. This resulted in Emera overstating the amount of 2019 capital additions to be included in rate base. Staff recommended that a 3-year average of when Emera's capital additions actually occurred during 2014 to 2016 be used to calculate the 2019 capital additions. Staff calculated this amount to be 23.41% and proposed a rate base reduction of $7,808,960 before adjusting for associated changes in depreciation and taxes. Corr. B.A. at 81.

In its Rebuttal Testimony, Emera noted that Staff's view appeared to be based on a combined history of Emera's major capital spending and base capital spending, rather than just base capital spending and that this led to a misplaced view that Emera's past history does not support a track record of placing into service 50% of its planned base capital additions in the first six-months of the year. Chahley/Davoren/Therrien Reb. Test. at 5 – 6. Emera further stated that it had not forecasted any major capital going into service prior to the end of the rate effective period (June 30, 2019) making the reliance on historical combined major and base capital investments misleading. *Id.* Emera stated that it examined the actual spending profile of base capital spending for the period of 2015 – 2017 and that given the short-term nature of base capital spend (i.e. customer connections, pole replacements, etc), the spend profile for base capital spending is more representative of the in-service schedule for base capital spending than it is for major capital spending. Emera stated that the analysis in Attachment RR Rebuttal 5 showed that for the period of 2015 – 2017, in each year, Emera completed 45% of its base distribution capital program in the first six months of the year. *Id.* at 6 – 7.

In the Reply Bench Analysis, Staff accepted Emera's distinction between large capital projects and base capital additions and agreed that, as a general matter, base capital additions likely take less time to complete. However, Staff did not accept the Company's proposition that capital spending will, in real time, match plant additions. Staff stated that based on the information provided in ODR-004-002 for 2017, the Company spent and placed in service 56% of the "blanket" base capital additions, described as routine items such as fleet and new customer additions, prior to July 1. For non-blanket items, however, 47% of the spending occurred during the first half of the year, but only 14% was placed into service. Overall, this resulted in only 36% of total base capital additions being placed into service during the first half of 2017. Staff determined that this was not a material difference between when all the capital additions were placed into service and when the base capital additions were placed and service and continued to recommend the initially proposed adjustment contained in its initial Bench Analysis. Reply B.A. at 15. Staff, however, later recognized that its position in the Reply Bench Analysis was not equivalent with Staff's position in the Initial Bench Analysis. In the Initial Bench Analysis Staff calculated a 3-year average of all capital additions (2014 to 2016) to determine the amount of base capital additions to be included in rate base. This resulted in an approximate 23% allowance factor. In the Reply Bench Analysis, Staff relied on the 2017 non-major capital additions which resulted in a 37% allowance factor. 4/24/18 Tr. at 97-99. [5]

The OPA recommended removal of the 2019 capital additions from rate base because these additions were based upon a draft of the 2019 capital budget and that a "draft budget" does not qualify as known and measurable for ratemaking purposes. The OPA, therefore, recommends that $7,342,353 be removed from rate base. OPA Brief at 24.

---

[5] Staff updated the inputs in the supporting schedule for Figure 7 of the Reply Bench Analysis to reflect the data in Emera's Supplemental Response to ODR-004-002 that Emera referenced during the April 24, 2018 technical conference. In the Supplemental Response to ODR-004-002, Emera stated that certain projects were incorrectly reported as non-blanket projects instead of blanket projects which resulted in a shift of approximately $1.4 million from the non-blanket figure in ODR-004-002, Attachment C to the blanket figures in ODR-004-002, Attachment B. Emera provided Attachments D through F that reflected this reclassification. These updates change the 37% originally calculated to 39%.

Emera disagrees with both Staff and the OPA. Emera states first that it has estimated the 2019 capital additions in the same manner as it did in its last rate case and that no party took exception to it at that time. Emera Brief at 16. Emera also notes that based upon its revised project classifications, if the Commission were to adopt Staff's approach, the percentage used should be 39% and not 37%. Emera states that its approach of using base capital spending as a proxy for the amount of plant that will go into service, is reasonable because there is a close correlation between spending and the amount of base capital that will be put into service at any time. Emera agrees with Staff that the correct standard is new plant in service but Emera is confident that base capital spending is an accurate proxy for that standard. *Id.* at 17.

Emera also states that if the Commission favors Staff's approach, then that methodology must be applied in a balanced manner to capture all base capital spending for those projects that went into service after January 1, 2018. Emera notes that it included all capital spending in 2018 and in the first six months of 2019, regardless of whether it resulted in new plant in service. Emera argues that essentially its method excluded some 2017 spending that should have been included and included some 2019 spending that should have been excluded but those amounts are roughly equal and therefore, offset each other. *Id.* at 17. Emera argues that the Commission should understand that if Staff's methodology is applied unevenly, as Staff has proposed, the risk of ratepayer harm resulting from incorrectly including some plant in rate base a few months before it is placed into service is much less than the risk of shareholder harm resulting from incorrectly excluding some plant in service from rate base until Emera's next rate case because there will be no true-up to capture lost depreciation and earnings on those assets for the few years between rate cases. *Id.* at 18.

b. <u>Decision</u>

The Commission does not find merit in the OPA's argument that no base additions should be included for 2019. All budgets are estimates and the fact that Emera had labeled its 2019 budget as "draft" does not mean that no such additions will take place especially given that, historically, these types of additions take place each year. The real question here is not whether, but how, the estimated rate base additions to be included in rate base should be calculated.

The Commission first finds that Emera's 2019 base capital additions to be included in rate base should reflect when assets are likely to be placed into service and not when Emera's capital spending occurred. Plant does not go into rate base until it is placed in service – until that time, Emera records Allowance for Funds Used During Construction (AFUDC) which increases the amount of the asset based upon both the equity and debt components of the rate of return calculations. The higher plant value is then used when the asset is placed into service and serves as the basis of the return on and return of the investment.

The Commission further finds that the 37% percentage included in Figure 7 of the Reply Bench Analysis, which reflects only base capital additions, better represents when those types of projects are placed into service than the 23.41% used in the original Bench Analysis. The Commission agrees that the percentage used to calculate the level of 2019 base capital additions should be updated from Staff's 37% to 39% but does not agree that any adjustments beyond this should be made. Emera's representation in its Brief that any improper inclusion of 2019 capital spending is offset by the exclusion of 2017 capital spending is just that; it is not supported by any factual analysis in the record.

Finally, the Commission disagrees with Emera's statement that not taking exception to a position that was used to calculate rate base in a prior proceeding means tacit approval. When the Commission becomes aware of a questionable methodology in the proceeding in front of it, it must address it so that going forward the correct methodology is used. In addition, other than Emera's statement in its Brief that it used the same methodology in the last proceeding, there is no factual basis for this statement. Even if Emera's argument were supported here, it misses the central point of Staff's analysis which is the relationship between rate base and capital spending over the first six months of a calendar year is different than the relationship that exists between these items over the full calendar year.

Based upon the discussion above, base capital additions to rate base for 2019 should be adjusted to reflect that only 39% of the base capital spending will be placed into service during the rate effective year. This will reduce rate base by $3,180,097.[6]

4. CU – CIS Upgrade

a. Positions Before the Commission

As part of its direct case, Emera proposed including in rate base costs associated with upgrading its Cayenta Utilities – Customer Information System (CU-CIS). Specifically, Emera proposed including $6.1 million of investment based on its projections of the cost of the project. Of the overall budgeted amount, $4,012,000 is allocated to distribution rate base. The Company forecasts that the project will be completed in June 2019. In her testimony, Company Witness Holyoke testified that when Emera selected Cayenta Utilities for the project in 2011, it expected that an upgrade would be needed every five years. Given the issues Emera encountered in its original implementation (the project was not implemented until 2015), the timing of the upgrade is right on schedule. Holyoke/Richardson/Belliveau/Ravin Dir. Test. at 37.

In the Bench Analysis, the Staff noted it had a number of concerns about the cost, timing and implementation of this upgrade, as well as its necessity. Based on the Company's past CU – CIS implementation record, and the responses provided by the Company during the technical conference, the Staff recommended excluding the Company's proposed adjustment from rate base in this case. Corr. B.A. at 58.

The OPA, through the testimony of its witness Lafayette Morgan, also noted its opposition to including the CU upgrade in rate base. In support of its opposition, Mr. Morgan points to the fact that the amount to be included in rate base is based on a preliminary budget which has a range of between $5.5 million and $7.75 million which reflects the fact that the project is at the high-level scoping phase and subject to

---

[6] Emera's proposed 2019 Base Capital Additions of $14,744,794 x 2 = $29,489,588 x 39% = $11,564,697. $14,744,794 - $11,564,697 = $3,180,097.

uncertainty. Morgan Dir. Test at 7. Mr. Morgan also points to additional uncertainty given the fact that the Company is still in the process of determining how to incorporate the Maine Public District into the CU – CIS billing system. The Company's statements, therefore, raise concerns about the cost of the project, the timing of the project, and whether the project should proceed at the same time that options for resolving the Company's CIS problems are still being explored. Mr. Morgan noted that much of the justification for including the project in rate base is based on the Company's budget. However, to be included in rates, the quantification of the costs should be known and the project should be certain. *Id.* at 9.

In its rebuttal case, the Company explained that since it is not on the most recent version of the CU system, fixing issues as they are identified becomes a much longer and drawn out process which in turn increases the costs of the fixes. The Company explained that it has already delayed the upgrade by approximately two years and that further delay would only increase the cost because the list of needed code changes would grow. Holyoke/Richardson/Belliveau/Ravin Reb. Test. at 48. With regard to project implementation, the Company noted that the Executive Sponsor of the project will be Mike Herrin, Emera's Chief Operating Officer, who successfully oversaw the implementation of TECO's new SAP customer information system. *Id.* at 51.

b. <u>Decision</u>

We agree with the Company that its decision to upgrade the CU – CIS system is reasonable. We do not believe, however, that there is sufficient basis to include this investment in rate base at this time given the uncertainty surrounding the actual costs of the project and also when the project will be completed.

The test year is designed to reflect a utility's costs and revenues during the rate effective period. To be included as part of an adjusted test year, new investments must be both "known" and "measurable". To be "known" any change to the test year must be reasonably certain as to whether and when it will occur. To be considered "measurable" the amount of the change must be reasonably certain. *Camden and Rockland, Maine and Wanakah Water Companies, Proposed Increase in Rates,* Docket No. 1993-00145, Order (Part II) at 7 (July 12, 1994).

In its initial testimony in the case, the Company noted that its rate base addition was based on a preliminary budget and although the project estimate was developed with the assistance of IT project consultants, Tata Consultancy, the numbers were still subject to uncertainty since the project was still in the high-level scoping phase. Holyoke/Richardson/Belliveau/Ravin Dir. Test. at 36. In response to discovery, the Company stated that Tata's estimate for the upgrade was $5,089,040. Emera's estimate included additions to Tata's estimate for organizational change management, overheads and AFUDC. In addition, although Tata included a contingency in each component of its estimate, Emera added an additional line for contingency based on its experience with the original CU – CIS implementation. The Company concluded that total costs of the CU – CIS project could, therefore, range from the current estimate of $5.5 million up to $7.75 million based on the assessment completed to date and that "the Company provided a single targeted figure of $6,186,600 because the process requires the Company to present a single number rather than an estimated range."

EXM-002-036. Given this evidence, the Commission finds that the costs of the CU – CIS upgrade are not “measurable.”

In addition, the completion of the project during the rate effective period seems similarly uncertain. At the time that the Company submitted its direct case, a System Integrator for the Project, which comprised $2,366,500 of the total $6,180,600 budget, had not yet been selected nor had an RFP been issued for this position. EXM-002-033. The Company has not updated this information as part of its rebuttal case to indicate that either of these events have occurred. Tata Consultancy projected a 12-month timeline to implement the project. EXM-002-034. Given this timeline and the current status of the project, the completion of the project by June 2019 seems highly uncertain. In addition, we would note, as extensively discussed in *Docket No. 2015-00360,* the Company’s past difficulties with accurately projecting costs and implementation completion dates for the CU – CIS project create additional uncertainty here.

The Commission concludes, therefore, that the Company’s proposed rate base adjustment for the CU – CIS upgrade should be rejected. In addition, the associated adjustment for the amortization of these costs should also be removed from revenue requirements.

5. <u>Other IT Spending</u>

a. <u>Positions of the Parties</u>

In its October 2, 2017 Customer Experience Testimony, the Company laid out its current information technology (IT) plans as well as some of its near and longer term IT thoughts and goals. In its Operations and Reliability testimony, the Company provided its budget plans for its GIS IT project. Some of the items discussed have cost estimates, while others were in the preliminary planning stages. Included in this overall budget were amounts for the “Bill Advisor” project ($675,000), and approximately $2 million for software upgrades related to operations and reliability. Holyoke/Richardson/Belliveau/Ravin Dir. Test. at 42.

In the Company’s Customer Experience Testimony, Ms. Holyoke explained that the Company was seeking recovery for the “Bill Advisor” project which contained three parts: High Bill Alerts, Energy Insights and a CSR High Bill Call Tool. The cost of the program was forecast to include capital costs of $675,000: $545,000 for Opower implementation and $130,000 to cover additional integrations. Annual licensing fees of around $250,000 are considered part of O&M and are included in operating expenses. *Id*.

In its Bench Analysis, Staff recommended excluding from revenue requirement the Bill Advisor upgrade, PowerOn upgrade and GIS/CYME interface upgrade. Staff did not object to Emera’s request for IVR re-design, but expressed concerns that it would be completed on time. Corr. B.A. at 60-64.

In the Company’s Rebuttal Testimony, it claimed that the Bill Advisor Project is on schedule and on budget for an early spring implementation.” Holyoke/Richardson/Belliveau/Ravin Reb. Test. at 57. The Company claims “all functionality designed as part of the IVR redesign project will be implemented in March 2018 and therefore the full investment is used and useful within the rate effective period." *Id.* at 59.

Regarding the GIS System improvement costs, OPA Witness Morgan suggested that based on the Company's response to EXM-004-046, an enterprise solution was still being considered instead of the GIS system, suggesting that the GIS system improvements are no longer know and certain. For this reason, Mr. Morgan decreased rate base by $631,000. Morgan Dir. Test. at 13. The OPA did not comment on other specific projects listed above such as the "Bill Advisor" or IVR project.

In its Reply Bench Analysis, Staff stated that, based on the Company's rebuttal testimony, its position had evolved to suggest that the following two projects appear as though they will be implemented and used and useful during the rate effective period:

- An upgrade to the existing GIS software to a newer version that is supported by the vendor ($618,000 budget in 2018 rate effective year); and

- An upgrade to the existing Outage Management System (OMS), PowerOn. ($462,000 budget in 2018 rate effective year)

Reply B.A. at 16.

In addition, based on information provided by Emera subsequent to the time of the filing of the Bench Analysis, regarding both the selection criteria for the Bill Advisor, as well as confirming that the project is currently on schedule and is estimated to be completed in the spring of 2018, Staff believed that Emera has provided the information necessary to support the inclusion of the Bill Advisor project in rate base. *Id.* at 17. However, based on Emera's response to ODR-001-031, Staff did not believe that the GIS/CYME interface upgrade and procurement of an outside consultant to populate the MPD GIS infrastructure database projects will be installed during the rate effective period. *Id.*

b. <u>Decision</u>

Based on the information provided subsequent to the filing of the Staff's Bench Analysis and the OPA testimony, the Commission accepts the Company's adjustments for the GIS software, Outage Management and Bill Advisor Projects. Based on the Company's own projections, the Commission finds that the CIS/CYME interface upgrade and the MPD GIS database project will not be in-service until after June 30, 2019. ODR-001-031. Therefore, the costs associated with such projects should be excluded from rate base.

6. <u>Customer Experience Fund</u>

a. <u>Positions Before the Commission</u>

As part of its direct case, the Company proposed a $2.1 million adjustment to rate base for "customer experience capital enhancements." Holyoke/Richardson/Belliveau/Ravin Dir. Test. at 42. The Company identified the following enhancements which were under consideration for implementation: customer self-service portal; enhanced outage map; text outage notifications; customer communication preference portal; and bill redesign and alignment. Ms. Holyoke testified that some of the solutions were dependent upon the decisions that have to be made concerning the future of the Maine Public District CIS and until that decision was made, the Company was reluctant to move forward with customer experience enhancements that may need to be reconfigured under a new system. Nonetheless, while it was not clear which specific projects would be implemented during the rate effective period, the Company was certain that it should invest a "base" amount of capital in customer facing technology improvements. Thus, Ms. Holyoke testified that while slightly untraditional, the "undesignated capital fund" could be seen as analogous to the base capital spending and included in rate base in this proceeding. *Id.* at 43.

In his testimony on behalf of the OPA, Mr. Morgan stated that he believed that the adjustment proposed by the Company was not appropriate because the costs were not known and measurable. Mr. Morgan disagreed with the Company's comparison to T&D base capital projects, since funds for the base capital budget are generally included in rate base because of many years of experience which allows the Company to determine a reasonable forecast for those costs. In contrast, the "customer experience capital fund" is newly created with no prior experience to gauge the reasonableness or the measurability of the amounts. Morgan Dir. Test at 10.

The Staff, in its Bench Analysis, expressed views similar to those expressed by Mr. Morgan. The Staff noted that base capital additions to rate base were supported by an established distribution planning process and were based on known quantifiable data. Corr. B.A. at 62. Additionally, the Staff noted that given the number of other issues facing the Company, as well as the Company's current rate levels and other pressures on its rates, it was not clear that the focus on these undesignated projects was appropriate at this time. *Id.* at 63.

In its Brief, the Company states that the Customer Experience Team is prioritizing the identified projects, noting that some of the projects depend on decisions related to the future of the Maine Public District. Emera Brief at 34. The Company also reiterated that the customer experience fund was similar to base capital program investments and that the Company needs both the funding and the flexibility to invest in new technologies to address customers' technology needs. *Id.* at 37.

b. Decision

As discussed above, to qualify as an adjustment to test year rate base, a project must be reasonably certain as to whether and when it will occur and the amount associated with investment must be reasonably certain. *Camden and Rockland, supra.* at 7. Based on the evidence submitted in this case, the Commission finds that almost by definition, the investments proposed in the Company's "undesignated customer experience fund" are not reasonably certain to occur nor is there any certainty as to when the investments will occur. As such, the "undesignated customer experience fund" investments do not qualify as a known and measurable adjustment to the test year.

The Company is correct that the Commission in the past, and in this case, has accepted adjustments for investments such as the Company's base capital spending program. These adjustments for rate effective year spending are known as attrition type adjustments. As the Commission explained in *Bangor Hydro-Electric Company, Proposed Increase in Rates*, Docket No. 1997-00116, Order at 22 (Feb. 9, 1998) the standards that we apply to adjustments in the attrition analysis are slightly different than those applied to test year adjustments, where a strict known and measurable standard is observed. The Commission went on to note:

> In an attrition analysis, the degree of precision by which proposed adjustments are evaluated and measured must, by their nature, take into account the lesser degree of certainty that surrounds projections of the items involved. An attrition analysis looks at a future period, the first rate effective year, and tries to project, using educated estimates and forecasting mechanisms, how that future will affect the operations of the utility. In other words, it tries to determine if there will be a change from the test year level of operations that would reduce or enhance the utility's ability to earn its authorized return. Because an attrition examination is based largely on projections, greater caution must be applied when deciding whether or not to include an adjustment in the Company's revenue requirement calculation. Of course, the line between a known and measurable test year adjustment and an attrition adjustment is not a bright one, and each proposed change must be examined individually.

Id.

Applying the attrition standard set forth above to the Company's customer experience fund does not yield a result different than the result produced when the known and measurable standard is applied. Unlike the base capital spending program which the Company analogizes to, there is no history of spending on such projects nor is there any indication of whether, or when, such spending will occur. As such, there is no basis to make even an educated forecast of such spending in the rate effective year. Therefore, the Company's proposed rate base adjustment for the "undesignated customer experience fund" investments is rejected. All such investments, along with the expenses associated with such investments, should be removed from revenue requirements in this case.

7. <u>Cash Working Capital (PERC and other PPAs)</u>

In its initial filing, the Company calculated a cash working capital allowance of $3,385,365, which included the working capital requirement associated with Purchase Power Expense and Off-system Sales. The Company's proposal did not include any adjustment to recognize that the contract with Penobscot Energy Recovery Company (PERC) terminated at the end of February 2018.

In the Bench Analysis, Staff adjusted the working capital requirement to remove any revenue or expense associated with the PERC contract, thereby reducing the working capital allowance to $2,317,201. Corr. B.A. at 90. In its rebuttal filing, Emera updated its calculations to remove the effect of the PERC contract and to include the effect of two additional power purchase agreements authorized by the Commission, Pisgah Mountain wind farm and the second phase of the Exeter Agri-Energy project. Chahley/Davoren/Therrien Reb. Test. at 9.

The Company argues that the cash working capital issue identified by Staff in the Bench Analysis now appears to be resolved and that the Commission should determine that Emera's working capital allowance is $2,603,467. Emera Brief at 24. We agree with Emera's characterization of the issue and with the revised calculations supporting a cash working capital allowance of $2,603,467.

8. Acadia Substation Investment

In *Emera Maine, Investigation of Inclusion of Acadia Substation in Rates*, Docket No. 2017-00018, Order (June 25, 2018) (*Docket 2017-00018*) the Commission found that Emera Maine was imprudent in the management of its Acadia Substation project. As a result, the Commission determined that $5,574,357 should be used as the initial distribution rate base for the Acadia Substation. The revenue requirements in the case shall be calculated in accordance with our decision in Docket *2017-00018*.

B. Cost of Service

1. Inspection Catch Up

a. Position of the Parties

In its initial filing, Emera sought to include $70,430 to complete the make-up work associated with not performing visual line inspections as identified in the Liberty Report Audit. Staff's position in the Bench Analysis was that Emera should not be allowed to recover this incremental cost as the initial inspections that were not performed were included in rates. Emera responded that the $70,430 included in its request was reasonable because Emera did not include sufficient inspection costs in previous rate requests, therefore, Staff's concern that the make-up work represented a double counting of inspection cost was not accurate. Chahley/Davoren/Therrien Reb. Test. at 10. The OPA did not comment on this matter.

In its Brief, Emera again argues that the full amount of $221,429 should be included for line inspections since not only had the $70,430 not been previously recovered in rates, but the Company was under-recovering for the make-up work it was performing. In addition, the management efficiency adjustment implemented in the last rate case was already serving as a penalty so additional disallowance was not warranted. Emera Brief at 47.

b. Decision

The Commission agrees with the Company that the $70,430 included for completing lapsed inspection work is not a double counting of inspection costs as these costs were not included in the past test year expenses. The Company has provided the forecast for completing the remaining inspection program and the test year amount proposed by the Company is not representative of the remaining annual program costs as evidenced by the following table.

Figure III.1[7]

Distribution Line Inspections - Catch Up Work	2016	2017	2018	2019
Total Miles for Program (including catch up)	1,486	1,340	1,329	1,334
Total Costs for Program (including catch up)	$221,426	$94,784	$93,924	$190,628
Approximate Miles for Balanced 6 yr Cycle Program	1,013	1,013	1,013	1,013
Catch up Miles (1 - 3)	473	327	316	321
Catch up Miles as a % of Total Miles (4/1)	32%	24%	24%	24%
Costs for Catch Up Miles (2 * 5)	$70,480	$22,748	$22,542	$45,751

The rate year cost of $34,145[8] is an appropriate amount to include for the make-up inspection work. This represents a decrease of $38,285 from the proposed test year cost associated with the line inspection program.

2. Vegetation Management

a. Position of the Parties

As part of its direct case, Emera proposed to increase the frequency of its vegetation cycle trim program from the current six-year cycle to a five-year cycle. Under this proposed change, Emera would be trimming 205 more circuit miles per year than under the current six- year plan. Emera notes in its testimony, moving to a five-year cycle would be consistent with the vegetation management cycle currently administered by CMP. Belliveau/Ravin/Richardson/Holyoke Dir. Test. at 27. Emera estimates the average annual incremental spend for the cycle trim work would be approximately $754,000. OPA-01-012. However, the increase from the test year to the rate effective period would be $2,068,331, inclusive of the enhanced inspections and Danger Tree programs. EXM-006-020. The difference between the average increase and the proposed rate year increase is a result of a relatively low test-year spend. In 2016 Emera trimmed 902 circuit miles against a five-year average of 1,111 circuit miles. EXM-004-019 Attachment A. Additionally, in its updated filing of December 12, 2017, the Company proposed to increase the amount for this expense by adding $55,340 for test-year internal labor costs. Emera explained that, “the original filing had non-labor amounts in the test year and labor amounts in the forecasted values, which created a mismatch. This was corrected by adding the labor amount to the test year amount.” EXM-006-020.

In its initial testimony, the OPA argued that Emera’s proposed five-year vegetation cycle trim program and enhanced Danger Tree program request should be

[7] EXM-004-033, Attachment A
[8] The rate year amount is the product of ½ of the 2018 amount plus ½ of the 2019 amount.

reduced by $968,884. To arrive at this reduction, the OPA used a three-year average for the cycle trim work and netted the estimated $63,000 annual O&M savings resulting from the enhanced Danger Tree program against the proposed cost increase. Morgan Dir. Test at 17.

In its Bench Analysis, Staff was supportive of the move to the five-year cycle as well as increasing Danger Tree efforts. However, since Emera's costs were estimates made prior to issuing a competitive bid package, the incremental cost sought by Emera was not sufficiently defined. In addition, the Staff noted that in its updated filing of December 12, 2017, the Company increased the amount for this expense by adding $55,340 for test-year internal labor costs. To the extent that test year vegetation management costs are increased for internal labor, Staff believed that a corresponding reduction to the overall labor expense should be made. Corr. B.A. at 91.

In its Rebuttal Testimony, Emera noted that the OPA's reliance on historical costs in its average expense amount did not account for the move from a six-year to a five- year cycle and the additional 205 circuit miles that would require trimming under the new plan. Additionally, Emera explained that the OPA overstated the savings from the enhanced Danger Tree program. According to Emera, the OPA included associated savings for the entire year but given the nature of the work, the savings resulting from avoided outages would occur only after the program had been in place for a full year. Emera clarified that when it estimated the customer interruption savings resulting from the Danger Tree program, the Company projected 25% of the annual savings for 2018, since the savings lagged the program year, resulting in estimated savings of $15,750 for 2018 and $63,000 for the full year of 2019. Chahley/Davoren/Therrien Reb. Test. at 34-35.

In its Reply Bench Analysis, Staff proposed including one-half of the incremental cost of the estimated increase from the Vegetation Management program in rates beginning July 1, 2018 and reconciling any remainder based on actual costs of the program based on adherence to the established cycle-trim schedule. Staff argued that such a reconciliation mechanism is consistent with the provisions of 35-A M.R.S. §3195 since this mechanism will increase the incentive for the Company to be efficient and to complete all circuits scheduled for trimming within the cycle. Reply B.A. at 19.

On May 2, 2018 Emera provided a supplemental response to EXM-006-020 in which the Company explained that its initial response was not entirely complete. After additional review, the Company concluded that it had double counted costs associated with a merit salary increase related to the vegetation management of $5,936. Emera proposed to reduce its revenue requirement by $5,936. Emera, in its Brief, opposes the Staff's recommendation to include one-half of the incremental cost of the vegetation management program in rates and reconcile the remaining incremental cost associated with the cycle trim and enhanced Danger Tree program.[9] Emera argues that although bids had not been received from prospective contractors, they were not expecting a significant reduction in price per mile, and therefore, the risk of unknown cost of the program did not outweigh the additional cost of deferring some amount of the annual vegetation cycle trim costs. Emera states that if the Commission determines a

[9] Emera accepts Staff's position that $224,420 for enhanced ground pole testing, infrared scanning and ultrasound testing should not be subject to the deferral account.

reconciliation approach is warranted, it proposes allowing 90% of the requested increase in rates in this case and limiting the amount that may need to be reconciled as much as possible. Emera Brief at 46-47.

In its Brief, the OPA generally agrees with Emera on the treatment of the Danger Tree savings and proposes to reduce the amount of savings to $31,000, or one-half of the identified full year program savings. The OPA continues to recommend that a reduction of $937,844 be applied to Emera's request for vegetation management programs. OPA Brief at 34.

b. Decision

The Commission finds that Emera's proposal to move from a six-year cycle trim program to a five-year cycle is justified. The five-year cycle will allow the Company to more aggressively manage vegetation problems and will aid in reducing tree caused outages. The Company is seeking $1,092,572 in additional funding to move to the new cycle as well as $458,000 to enhance its efforts in addressing Danger Trees. We find that the OPA's approach to average a three-year period based on a six-year cycle would not accurately reflect the costs of Emera's new program. However, we do not agree with the Company's proposal to include the full amount of the projected vegetation management costs in this rate year based on its current estimates.

As has been noted by Staff, CMP's program cost on a per circuit mile basis decreased in the second cycle of their program. Emera has argued that they do not envision experiencing the level of savings seen by CMP due to cycle trim historical differences. Additionally, Emera has testified that historically there has been limited vendor interest in competing for the cycle-trim contract but this year they expect multiple bidders. 03/15/18 Tr. at 44. Emera is requesting increases in this case for a program for which it has not yet issued an RFP. It appears that Emera had ample time to solicit bids so that prices would be known prior to the hearings in this case, but has not done so. A competitive process may also apply downward pressure on program costs. This suggests there is sufficient uncertainty in future vegetation management costs both in terms of the level of cost and as to the timing of the implementation of the program.

As such, we find the Staff's proposal to establish a deferral account to be trued up in a future proceeding to be a reasonable way to address the uncertainty of the needed budget increase. While Staff proposed including half of the incremental cycle trim and Danger Tree costs into rates, we find that 75% of the incremental cost, or $1,162,929, to be more reasonable and more likely to lead to a smaller reconciliation amount. Therefore, $387,643 will need to be removed from the Company's revenue requirement. As described in the Reply Bench Analysis, the difference between the included and actual amounts could be reconciled as part of a rate plan if such is adopted; as part of a mechanism to reconcile tax savings if such is adopted; or as part of the Company's next base rate case. Given our holdings in other parts of this Order, the most logical way to approach this reconciliation would be to include the reconciliation at the same time that 2017 storm costs and the amortization of the excess deferred taxes are addressed.

In addition, we find that it is justified to reduce the revenue requirement by $39,375 to reflect the benefits resulting from its enhanced Danger Tree program. This savings was calculated by averaging the projected annual O&M savings identified by the Company for 2018 and 2019. However, as the savings are a result of reducing Danger Tree caused outage restoration costs, this credit is most appropriately applied to lowering the amount requested for storms.

Finally, the Commission finds that Emera has double counted internal labor costs associated with the vegetation management program. The Company stated at the May 3, 2018 hearing that "we did confirm that there was no double counting of vegetation management costs in the 2016 test year. That was taken directly from the FERC Form 1 so there's no double counting." 5/3/18 Tr. At 47. The question here is not what is on the FERC Form 1, the question is that the Company moved expenses into the vegetation management category without a corresponding reduction to internal labor costs. This results in a double counting which requires a $55,340 reduction to internal labor costs in the calculation of revenue requirement.

3. Non Labor Regulatory Expenses

a. Positions of the Parties

In its direct case, Emera proposed inclusion of rate year non-labor regulatory expenses totaling $708,669. Chahley/Davoren/Therrien Dir. Test. at 76. This amount is composed of: 1) 2014-2016 average non-rate case regulatory costs of $164,768 adjusted for inflation to $173,266, 2) five-year normalized rate case costs based on the 2016 rate case of $136,805, 3) five-year normalized 2015 and 2016 cost of service study costs of $98,598, and 4) proposed rate design study costs of $300,000. *Id*. at 74 – 75.

The OPA objected to the inflation adjustment on the normal ongoing costs as well as inclusion of the rate design study costs, and calculated allowable costs of $401,268. Morgan Dir. Test. at 15, LKM-13. The OPA contends that it is improper to apply an inflation adjustment to regulatory costs because these costs do not track inflation. OPA Brief at 28. Rather, the OPA asserts that these costs fluctuate with the specific nature of the work completed in a particular case, which may be different from previous cases. *Id*. The OPA also recommends that the proposed $300,000 for a rate design study should not be allowed in rates at this time, citing the uncertainty of the actual amount and timing. *Id*. at 27.

In the Bench Analysis, Staff objected to the Company's inclusion of rate design study costs. Corr. B.A. at 94. Staff argued that it was not certain that the costs would be incurred in the rate effective year and also asserted that the Company had not provided a basis for its $300,000 cost estimate. *Id*. at 95. In addition, Staff suggested that if the Commission determines that it is appropriate to include the costs, they should be normalized over a longer period than rate case costs and proposed that a ten-year period would be appropriate. *Id*. at 95-96.

In its rebuttal case, Emera changed its position on the recovery of-non-labor regulatory expenses and proposed what it called an "alternative ratemaking treatment." Chahley/Davoren/Therrien Reb. Test. at 18. By way of this proposal, Emera requests inclusion of $150,312 representing the four-year average of recurring regulatory expenses, adjusted for inflation. In addition, the Company has created a $3,127,036 regulatory asset which represents the 2014 and 2016 rate case expenses not yet recovered through base rates, the cost of the instant rate case, as well as $300,000 for its proposed rate design study. The Company requests inclusion of $625,407 which represents the five-year amortization for non-recurring expenses. Emera Brief at 27, Exhibit RR-71. The Company argues that due to the frequency of its recent rate case proceedings, it has not fully recovered its costs associated with those prior cases.

With regard to the rate design study costs, Emera states that it is confident that the study will be completed during the rate effective period and expects to file the study with the Commission in November 2018. Emera Brief at 26. Staff suggested in the Bench Analysis that it would also be more appropriate to spread the costs of such study over ten years, rather than five, given the infrequency with which they are typically conducted. Emera responds in its Brief, stating that if the Commission finds Staff's argument compelling, it must also consider the recent frequency of rate cases and contends that a two-year normalization period, rather than the five-year period historically used, would be more reflective of the actual period between rate cases. *Id*. at 30.

The OPA rejects the Company's treatment of non-recurring regulatory costs, arguing that amortization of those costs does not comply with Commission rules or precedent. OPA Brief at 29. Staff did not express a position with regard to the Company's request to amortize non-recurring regulatory expenses, however, at the hearing Staff indicated that the proper treatment is normalization rather than amortization. 5/3/18 Tr. at 155-157.

b. Decision

The Commission disagrees with the Company's proposed treatment of non-recurring regulatory expenses. The Company observes that "the question is: did the Commission intend to allow Emera to fully recover its actual non-recurring regulatory expenses" in the prior rate proceeding. Emera Brief at 29. Emera asserts that the Commission intended to allow the Company to fully recover its actual costs over a five-year period and, therefore, it is appropriate to allow recovery of the unrecovered portion. *Id.* The Commission disagrees.

Commission rules specify that "[t]he Commission will set regulatory proceeding expenses on a normalized test year basis." MPUC Rules, Ch. 85, §3(A). The Commission believes that there is a fundamental difference between normalization and amortization and that the difference is not simply "an esoteric discussion of accounting semantics" as the Company suggests. Emera Brief at 29. The Commission has previously articulated its position on this issue. See *Central Maine Power Company, Proposal for Accounting Order on Hurricane Bob Service Restoration Costs*, Docket No. 92-019, Order (November 10, 1992) (*Hurricane Bob Order*). In that docket, the Commission stated that "deferral mechanisms should be used only … in specific situations where the amount of spending cannot be reasonably estimated with any certainty…" *Hurricane Bob Order* at 2. The Commission believes that regulatory costs can be reasonably estimated.

The Commission order in the last rate proceeding did not include any provision for deferral of non-recurring costs. If the Commission had intended to allow full recovery, it would have authorized amortization and established a regulatory asset at that time. Instead, as the Company correctly notes, "[i]n the last rate case, the Commission approved normalized treatment of major regulatory costs over a five-year period." Emera Brief at 28. Thus, in compliance with Chapter 85, the Commission correctly included normalized regulatory expenses in the cost of service calculation.

Furthermore, requests for accounting orders should be made relatively contemporaneously with when the costs are incurred. For example, when Central Maine Power requested an accounting order for significant environmental cleanup costs, the Commission expressed concern with "the practice of beginning a deferral and at some later time seeking Commission approval of the deferral." After CMP amended its original accounting order request to exclude the approximately $4 million incurred over the preceding five years, the Commission approved deferral of only those costs incurred after the request. See *Central Maine Power Company, Request for an Accounting Order Concerning O'Connor Site Clean-up*, Docket No. 91-216, Order (August 26, 1992) (O'Connor Order). Here, the Company is requesting regulatory accounting treatment of costs incurred as much as five years ago. Many of these costs were, in fact, incurred prior to the last rate case during which Emera did not request regulatory accounting treatment. Also, the inclusion of the rate design study costs, which have yet to be incurred, in a regulatory asset subject to rate base treatment and amortization, is inconsistent with generally accepted ratemaking practices. In accordance with Chapter 85 and Commission precedent, the Commission allows recovery of reasonable regulatory costs on a normalized basis.

The Commission also disagrees with the Company's inclusion of costs related to a rate design study as part of normalized costs to be established here. The Company asserts that it intends to file a rate design study with the Commission in November 2018. Emera Brief at 26. However, when asked at the hearing when the Company intended to file the rate design case Mr. Richardson responded:

> Well, our plan would be to -- I'm going to say do the detailed work to try to come up with the rate design that could be workable and supportable and be able to bring to the Commission, we've said sort of three to six months to do that evaluation. But my hesitancy is I believe there's an answer there that, if we put our minds to it, we can come up with it. But I -- it's not easy. It's not like there's an obvious, no brainer. So it's possible we're going to spend, you know, six months and not get as far as I hoped.

Hr. Tr. at 26-27. As the OPA observes, this response does not inspire confidence about when the case will be filed. OPA Brief at 28. In addition, the Commission agrees with Staff that the Company has not adequately supported the estimated $300,000 cost. The Commission does not accept this as a known and measurable adjustment, and therefore, finds that the cost cannot be included in rates at this time.

The Commission agrees with the Company that it is reasonable to include an adjustment for inflation, which is consistent with the methodology used in the last rate case. Although the Commission understands the OPA's point that total costs can vary significantly based on the scope of work completed, we believe that the underlying per-unit cost will also trend upward over time. We accept the Company's use of an inflation adjustment as a reasonable estimation of the cost increase.

In the Bench Analysis, Staff proposed that, if the Commission allows recovery of the rate design costs, those costs should be normalized over a period of ten years to better reflect the normal period between which the costs are incurred. Corr. B.A. at 95-96. Emera responded that if the Commission finds this argument compelling, the Company should be allowed to recover rate case costs over a two-year period which is reflective of the actual period between recent rate cases. Emera Brief at 30. In the last rate case, the Commission authorized a five-year normalization period for rate case costs as well as rate design costs that had been incurred. The Commission finds that this approach was reasonable, and accepts an overall five-year normalization period for non-labor regulatory costs.

Non-labor regulatory costs will be determined using the methodology proposed in the Company's direct case, excluding the $300,000 cost for the rate design study. This yields recoverable costs of $408,669, which is a disallowance of $367,050 from the amount requested in the Company's Brief. See Emera Brief at Exhibit RR-71. To the extent that the Company commences a rate design case and actually incurs costs for a rate design study, such costs may be considered as part of the normalized non-labor regulatory expense in the Company's next rate case.

5. Medical and Other Insurance

a. Positions Before the Commission

In its direct case, Emera included $729,205 for the distribution portion of its administrative and other medical insurance costs. Chahley/Davoren/Therrien Dir. Test. at 76. In the Bench Analysis, the Staff considered the 2016 actual test year amount to be an outlier and, therefore, used the amount of medical costs that had been incurred from January through September 2017 (at that time, year to date) and trended that amount forward using Emera's inflation rate. Corr. B.A. at 93.

In their Rebuttal Testimony, Chahley/Davoren/Therrien testified that the actual full year costs for 2017 were now available and were $708,194. This demonstrated that the 2016 was not an outlier and, therefore, no downward adjustment to the rate effective year amount of $729,205 was warranted. *Id.* at 14-15.

b. Decision

The updated data provided by the Company in its rebuttal case provides the necessary justification for the amount included in its filing for medical and other insurance costs. Therefore, the Commission accepts the amount contained in the Company's initial filing for this item.

6. Bonus Compensation

A component of the Company's total compensation includes a bonus incentive plan. The plan sets threshold, target and stretch goals in the categories of safety, people, customer, asset management and finance. Bonus payments are determined by the Company's performance in each category; the employee's classification and base salary; and the employee's individual performance. Emera Brief at 31. The Company included in its revenue requirement an amount based on the 2016 actual bonus incentive plan payout, $515,995. *Id.*

a. Positions of the Parties

In the Bench Analysis, Staff took the position that because of the concerns related to Company management and performance discussed throughout the Bench Analysis, it would not be appropriate to allow recovery of executive and management bonus compensation for financial performance from ratepayers. Corr. B.A. at 94. Staff calculated a disallowance amount of $149,929. *Id*. The OPA agreed with Staff's recommendation. OPA Br. at 32.

Emera argues that customers benefit from strong financial performance because over the long term it allows the utility to attract needed capital at competitive rates. *Id*. at 32. The Company contends that customer and shareholder values are not at odds but rather move up or down together. *Id*. at 33. Thus, it is appropriate to include all bonus compensation components to be recovered from ratepayers. Furthermore, Emera disagrees with Staff's assertion that management performance is unsound and, therefore, disagrees that Emera's management performance warrants disallowing costs associated with this component of its employee compensation. *Id*.

b. Decision

As the Commission recently recognized in *Northern Utilities dba Unitil, Request for Approval of Rate Change Pursuant to Section 307*, Docket No. 2017-00065, Order at 30-31 (February 28, 2018) (*Northern Docket 2017-00065*), as a general matter, incentive compensation should be considered along with base pay in determining reasonable compensation and that it is not the Commission's place to dictate the exact structure of the Company's overall employee compensation scheme.

In the case before us, the Staff and the OPA have challenged the Company's inclusion of bonus compensation in revenue requirements. For the reasons discussed in Section V *infra.*, the Commission finds that the Company's management performance has advanced to the point where an adjustment to the compensation levels based on management performance is not warranted.

In *Northern Docket No. 2017-00065,* the Commission concluded that Northern had adequately proved that its incentive compensation plan was a reasonable component of its total employee compensation. In the present case, while the Company has demonstrated the reasonableness of its base salary compensation, the Company has not demonstrated that its total overall compensation is reasonable compared to market conditions, or shown that its executive incentive compensation is needed to attract and retain qualified employees. EXM-006-005 Attachment A (Confidential), ODR-004-009 Attachment B (Confidential). The Commission, therefore, accepts the bonus incentive compensation adjustment proposed by the Staff and the OPA.

7. Storm Costs

a. Positions Before the Commission

The Company's test-year amount for non-extraordinary storm costs was $3,734,047. Using a four-year average (2014-2017) the Company calculated normalized non-extraordinary storm costs of $2,032,929 which resulted in a reduction to test year expense of $1,701,118. The Company stated that its use of a four-year average was consistent with the Commission's methodology in *Docket No. 2015-00360.*

Chahley/Davoren/Therrien Dir. Test. at 70.

In the Bench Analysis, Staff noted that in *Docket No. 2015-00360*, the Commission stated that it preferred to use a five-year normalization for storm costs. However, since 2012 costs were almost 20% less than the next lowest cost year, the Commission considered 2012 to be an outlier and dropped 2012 from the analysis. As a result, the Commission used a four-year average. Looking at the amounts for storm costs in this case, Staff noted that 2016 was approximately 50% greater than the next highest year in the data set and, thus, can also be considered an outlier. Applying the four-year outlier methodology resulted in a four-year normalized level of $1,411,019. If a straight five-year normalization is used, the normalized amount would be $1,875,624. Depending on the methodology used, the reduction to test year expense should be increased by either $622,174 (four year) or $157,305 (five year). The Staff recognized that these amounts needed to be updated for 2017 results. Corr. B.A. at 92.

In rebuttal, Emera agreed that multiple years of storm costs should be averaged and that complete 2017 results should be used in the calculation instead of partial 2017 costs. Chahley/Davoren/Therrien Reb. Test. at 13. Emera updated its 2017 storm costs to year-end actuals excluding the impact of the October 2017 windstorm, which is the subject of a pending accounting order request. Because the weather's impact on Emera's system varies considerably from year to year, and given the Commission's preference for a five-year period, Emera used five years of storm costs in the calculation of average storm costs (2013, 2014, 2015, 2016 and 2017). Emera disagreed with Staff that any year's actual costs (whether low or high) should be excluded as an "outlier" because given changing climate conditions there are no true outliers or anomalies despite the variances each year. Emera's revised methodology yielded an annual proposed storm cost of $1,973,782 (a reduction of $59,237 to Emera's initial proposal). *Id.*

b. Decision

The Commission is in general agreement with Emera's revised proposal. Given the volatility in current climate conditions, we find that it is appropriate to use a five-year average and not exclude any year as an outlier. As discussed in Section III (B)(2) above, storm restoration costs which result from this calculation should be reduced by $39,375 to reflect savings expected from the Enhanced Danger Tree program. This results in annual storm cost amount of $1,934,612.

8. Late Payment Revenue

a. Positions Before the Commission

In its direct case, Emera proposed to include $677,868 for customer late payment revenues in the rate year based on 2016 revenue of $600,520. Chahley/Davoren/Therrien Dir. Test. at 78. Staff countered that the customer late payment revenues should be increased by $184,148 based on a projected 2017 annualized revenue amount for customer late payment revenues of $693,227 (using year to date revenue available at that time), and applying an annual rate change of 15.44% based on a single-year growth rate to reach a rate effective year amount of $862,016. Corr. B.A. at 91-92.

In its rebuttal filing, Emera agreed to use 2017 data in the calculation, but disagreed with the approach of using a single-year growth rate as the appropriate measure of customer late payment revenue. Chahley/Davoren/Therrien Reb. Test. at 12. Consequently, Emera forecasted its customer late payment revenues based on actual 2017 data for the full year. Further, Emera increased that amount by the average actual growth experienced over two years, 2016 and 2017, rather than a single year. This resulted in a rate effective year amount of $749,983, or an increase of $72,115 in comparison to Emera's initial request. *Id.*

b. Decision

The Commission agrees with the use of 2017 actual data through year-end and using a growth rate based on actual growth experienced in 2016 and 2017. The Commission finds, however, that the 2018 revenue amount should be trended forward to 2019 to come up with the appropriate rate effective year amount. Doing this additional trending results in a rate effective year amount of $787,218[10] which represents a $109,350 adjustment to the Company's direct case.

C. Impact of the Tax Cuts and Jobs Act

1. Overview

In late December 2017, Congress passed the Tax Cuts and Jobs Act (TCJA or Tax Act) which was subsequently signed by the President and became law on January 1, 2018. Among other provisions, the TCJA reduced the corporate tax rate from 35% to 21%. As part of its Bench Analysis, Staff requested that Emera Maine, as part of its Rebuttal Case, address the impacts of the TCJA on its revenue requirements including the excess deferred income taxes (EDITs) that would result from the reduction in the tax rate.

By way of explanation, EDIT's are a result of the difference in tax depreciation and ratemaking depreciation (required by IRS normalization rules) and the reduction in the tax rate. The higher amount allowed for tax depreciation in the earlier lives of assets when compared to ratemaking depreciation creates Accumulated Deferred Income Taxes (ADITs). These ADITs essentially represent a pre-payment of taxes by ratepayers which is used as an offset to rate base. These ADITs reverse over time

[10] Calculation based on $749,982 x 1.0993 = 824,455 + 749,982 ÷ 2 = $787,218.

when tax depreciation is less than book depreciation. However, when the tax rate is reduced, as was the case here, ratepayers essentially overpaid the pre-payment. This overpayment is referred to as the EDIT.

In a Procedural Order issued on January 11, 2018, the Examiner directed Emera Maine as part of its Rebuttal Case to also address the issue of whether an accounting order should be issued pursuant to 35-A M.R.S. § 501, to establish a regulatory liability which defers for future flow-thorough to ratepayers the impact of the tax changes effective January 1, 2018. The Examiner noted that the question of the issuance of an accounting order had been included in the investigations of the impact of the TCJA on the justness and reasonableness of other utilities rates which had been initiated by the Commission.[11]

The Company has identified two distinct time periods for which the tax rate reduction impact needs to be quantified; January 1, 2018 through June 30, 2018 (the effective date of the TCJA through the last day at current distribution rates are in effect) and July 1, 2018 forward (the time period when new distribution rates are put into effect). Chahley/Davoren/Therrien Rebuttal Test. at 21. In addition, the Company identified two distinct aspects of the TCJA which impact revenue requirements; one which reduces current tax expense and the other involving the flow-through of the EDITs created by the reduction in the tax rate. We agree with the Company's classification of issues involved and believe that such a classification provides a useful framework for the Commission's analysis of the issues and the positions before us.

2. <u>Positions Before the Commission</u>

a. <u>Company</u>

In its Rebuttal Case, the Company's witnesses noted that there were two aspects of the TCJA which would impact the Company's revenue requirements; the reduction of the federal corporate income tax from 35% to 21% and the change in the availability of bonus depreciation. Chahley/Duvoren/Therrien Reb. Test. at 23. With regard to bonus depreciation, the Company's witness panel explained that the TCJA eliminated the availability of bonus depreciation to public utilities for assets placed in service after September 27, 2017. With regard to the period starting January 1, 2018, the Company agreed to incorporate the impacts of the TCJA using its best available estimates. *Id.* at 21. The Company discussed the Internal Revenue Service's (IRS) requirements that the EDITs created as a result of the tax reduction not be returned more rapidly than the amount that would be returned under the average rate assumption method (ARAM), which requires that the excess deferred taxes be reduced over the remaining lives of the property as used in its regulated books of account. If the Company's plant records were not sufficient to utilize the ARAM then the Company would need to use what is referred to as the Reverse South Georgia Method. The Company also noted the

---

[11] See Notice of Investigation in Docket Nos. 2018-00004, 2018-00005, 2018-00006, 2018-00007, and 2018-00008, *Commission Initiated Investigation of the Impact of the Tax Cut and Jobs Act of 2017 Pertaining to Central Maine Power Company, Maine Natural Gas Corporation, Summit natural Gas of Maine, Inc. Bangor Natural Gas Company, Inc. and the Maine Water Companies*, respectively.

distinction between Protected EDITs which must be amortized in accordance with normalization rules and Unprotected EDITs (non-depreciable assets which are in the reserve) which have no mandated treatment.

As of December 31, 2017, the Company recognized $80,448,123 of Excess Deferred Federal Income Tax Reserve. This amount includes $38,691,259 in the Distribution Reserve with the remainder of the $80.4 million attributable to Transmission. The Company noted that these amounts are based on its initial review of the Reserve and are subject to revision as the Company progresses through the process of determining the impact of the Tax Act. The Company has approximated the total Distribution related Protected EDITs to be $28,778,203, and the total Distribution related Unprotected EDITs to be $9,913,056. For the Protected EDITs, the Company has developed an estimated schedule by which the Protected EDITs will reverse in accordance with provisions of ARAM (for this estimate, the Company has assumed that utilization of ARAM will be allowable, but a final conclusion has not been made). For the Rate Effective Year, this amortization was determined to be $631,524. For the Unprotected EDITs, the Company has estimated the recovery period to be ten years, and the amortization for the Rate Effective Year to be $991,306.

Overall, the Company calculated a $6,216,303 reduction in revenue requirements as a result of the tax change. The Company provided the following summary of this overall reduction:

Figure III.2
Summary of Tax Reform Revenue Requirement Changes

	Change in Revenue Requirement
1. Change in the Effective Tax Rate	-12.7498%
2. Change in Revenue Requirement as a result of the change in the Effective Tax Rate	($4,023,320)
3. Creation of a New Regulatory Liability Related to Excess Deferred Income Taxes	($2,255,644)
4. DIT Rate Base Adjustments Affected by Tax Reform	($354,341)
5. Rate base Adjustment	($203)
6. Cost of Service Adjustments Affected by Tax Reform	$417,2016
Total Change in Adjusted Test Year Revenue Requirements resulting from Tax Reform	($6,216,303)

Id. at 51.

With regard to the January 1, 2018 through June 30, 2018 timeframe, the Company takes the positon that since it was in an under-earning position during this time period, as reflected by the fact that it was before the Commission for a rate increase, the Company should only be required to return the tax savings which would put it in an over-earnings situation. The Company's witnesses noted that the Company was relying on the tax savings to provide needed financial support for ongoing operations in 2018, including improvements to service in response to the Commission's Order in the last rate case. The Company stated that it would calculate the actual tax savings that occurred during the first six months of 2018 based on its actual earnings during this time period and then compare actual tax savings that occurred under the TCJA to what Emera would have paid in taxes under the old rate. *Id.* at 21.

By way of Supplemental Rebuttal testimony of Richardson/Chahley/Davoren/Therrien, the Company revised its position on the flow-through of the tax savings for the period commencing July 1, 2018. The Company's witnesses noted that the application of the tax savings presented an opportunity to counter balance other costs that Emera has recently incurred, specifically costs associated with the October 30, 2017 storm which is the subject of a Company request for an accounting order in Docket No. 2018-00021. The Company noted that it was requesting recovery of $7.3 million in that case and that it was unclear whether that case would be completed in time to incorporate such costs in the July 1, 2018 rate change. The Company also noted the increasing frequency and severity of storms and the fact that $5 million of recently deferred storm costs still remains to be recovered from customers. Richardson/Chahley/Davoren/Therrien Supp. Reb. Test at 5. The Company also pointed to other likely increases in costs such as the expiration of the amortization of $20 million of retiree medical savings and possible future investments, including automated metering infrastructure (AMI) and a customer information system for MPD. *Id.*

The Company thus proposed that the July 1, 2018 distribution rate increase not include either the tax savings associated with the Tax Act or the October 2017 storm costs. Instead, the Commission should direct Emera to accumulate the on-going tax savings as a regulatory liability. Emera did not propose a particular amortization time period in this testimony but believed that the parties should explore a time period that is based on using any tax savings (both the pre-June 30, 2018 excess savings and all of the post July 1, 2018 savings) that will accrue to the regulatory liability account to fully offset the storm costs. Once the tax savings equal the October 2017 storm costs, the regulatory asset and the liability associated with the tax savings will offset each other. As the regulatory liability associated with the tax savings grows over time, it could be used, with Commission approval, to offset Emera's other existing amortizations and once the annual cost of service has increased to the point where the annual tax savings are needed for the Company to fully recover its annual cost of service, the regulatory liability associated with the tax savings can cease. *Id.* at 6.

b. <u>OPA</u>

The OPA's position in this case is that the proposal originally put forth by the Company in its initial Rebuttal Testimony for the treatment of savings from the TCJA for the period July 1 forward correctly reflects the revenue requirement effect of the cost savings resulting from the federal income tax reduction, including the amortization of excess accumulated deferred income taxes by recording those savings in a regulatory liability account whereby the Company will pass the savings on to customers. OPA Brief at 18. None of the reasons cited by Emera in its Supplemental Rebuttal Testimony support postponing the flow through of the tax savings to its customers. The OPA notes that out of the $6,216,303 annual tax savings that the Company identified, $3,960,659 is related to the change in the tax rate. There is no reason to deny ratepayers the benefit of this amount since it simply reflects the change in the tax rate from the initial filing at the old tax rate to the current tax rate. *Id.*

The OPA takes the position that the EDITs for the rate effective period also should be flowed back to ratepayers since most of the EDITs to be flowed back relate to unprotected assets which are not subject to normalization requirements and also since the Company is already amortizing the Protected EDITs subject to “true up”. The Commission thus would not be requiring the Company to record costs that it is not already recording and, therefore, there is no legitimate reason to deny these savings to customers. *Id.* at 19.

Regarding the over-collected taxes for the period January 1 through June 30, 2018, the OPA argues that Emera’s rationale is flawed and unfair to ratepayers. Federal income taxes are a pass-through item not intended to affect a utility’s rate of return either positively or negatively. Providing for taxes through a gross-up of utility’s ROE ensures that the utility has the opportunity to earn its after-tax authorized return on equity. However, when tax rates are reduced, the benefits of that reduction should be flowed through to ratepayers as expeditiously as possible to prevent a windfall to shareholders. The savings attributable to the change in the tax rate here are significant, and are both extraordinary and unusual. Specifically, such a change has not been experienced since the enactment of the Tax Reform Act of 1986. Accounting for the change from the reduced tax rate would ensure that rates are just and fair. *Id.* at 21.

OPA Witness Morgan calculated the tax savings of $2.9 million for the reduced income tax rate for the period January 1, 2018 through June 30, 2018. Mr. Morgan testified that this amount should be transferred and held in a regulatory liability account and returned expeditiously to ratepayers. It should also include a carrying charge at the overall rate of return determined in this proceeding. Morgan Surr. Test. at 13.

c. <u>Staff</u>

As expressed in the Reply Bench Analysis, Staff’s view was that the full benefit of the tax savings should be returned to ratepayers and that this amount should be incorporated in rates effective July 1, 2018. To calculate the amount of tax savings from the January 1, 2018 – June 30, 2018 period, Staff calculated the return on equity from the last rate case using the 21% tax rate in the gross-up calculation, and compared that amount to the return required using the 35% rate in effect at the time. Based on this comparison, Staff estimates that the revenue requirement in the last rate case would have been $3,121,768 lower if the 21% tax rate was in effect. Assuming level earnings throughout the year, half of that amount, $1,560,884, is assumed to be attributable to the first 6 months of 2018. Reply B.A. at 3.

With regard to the regulatory liability established for the period of January 1, 2018 – June 30, 2018, the Staff accepted the Company’s revised position with regards the flow-through of the EDITs since the timing and the level of the flow-through of the Protected EDITs cannot be determined at this time. To the extent that the Company begins amortizing such protected EDITs prior to the time that such amortization is included in rates, the Company should defer such amounts in a regulatory liability account to be flowed back to ratepayers. In addition, the Staff accepted the Company’s proposed amortization schedule for its Unprotected EDITs.

The Staff did not, however, accept the Company's proposal to create a regulatory liability for the tax expense savings associated with the lowering of the tax rate for the period beginning on July 1, 2018. These savings should be reflected in revenue requirement in this case similar to other permanent increases or decreases in expenses. *Id.* at 4.

3. Decision

a. Treatment of Tax Rate Savings for the Period Beginning July 1, 2018

Under the provisions of 35-A M.R.S. § 301, public utilities are obligated to provide safe, reasonable and adequate service at just and reasonable rates. In determining just and reasonable rates, the Commission is to provide such revenue to the utility as is required to perform its public service and to attract necessary capital on just and reasonable terms. 35-A M.R.S. § 301(4). In the context of Section 301 of Title 35-A, the reasonableness of rates relates to both the shareholders and the customers. *New England Tel. & Tel. Co. v. Public Utilities Commission*, 390 A. 2d 8 (Me. 1978).

The TCJA has significantly decreased the Company's expenses for the rate effective year. Based on the Company's calculations of rate base and ROE, the reduction in the federal corporate tax rate results in savings of $4,023,320 for the rate effective year. Chahley/Davoren/Therrien Reb. Test. at 51. As a general matter, in order to ensure just and reasonable rates, and to ensure generational equity, a reduction in expense should be reflected in revenue requirements, and ultimately rates, during the course of a rate case proceeding. While it certainly is possible for the Commission to defer such a reduction in rates in order to promote rate stability, such action should be viewed as an exception to the general rule and should not be viewed as a long-term remedy.

In its second supplement to its Rebuttal Testimony, the Company corrected an error to its initial rate base calculation by removing $13,552,325 of deferred taxes which it had inadvertently included twice as part of its direct case and rebuttal. Inclusion of this correction increases the Company's rate increase by approximately $1.3 million. 4/24/18 Tr. 116. This change when coupled with some other corrections in the supplemental testimony would produce an increase above the initial amount requested of 12%.[12] As discussed in Section V(B), infra, the Company's ratepayers in this case have expressed significant concerns over the level of the Company's rates and the impact that a significant rate increase would have on them. It is often the case, that the Commission has very limited flexibility to recognize such concerns. In this case, given the passage of the TCJA, the Commission does in fact have some ability to lower rates and still provide the Company with a reasonable opportunity to recover its expenses.

We see no reason then not to pass on the savings resulting from the reduction in the federal tax rate in calculating revenue requirements for the rate effective period

[12] The Company has agreed, to the extent that the Commission's decision yields an increase above 12%, that it would limit its increase to 12% and fund the differential through a flow-through of the tax savings.

commencing July 1, 2018. In doing so, we are cognizant of the rate stability concerns raised by the Company. However, we believe that such concerns can be addressed by our determination regarding the treatment of other aspects of the TCJA discussed below.

b. EDITs

The Company's proposals regarding the flow-back of the EDITs for both January 1, 2018 through June 30, 2018 period and the rate effective period beginning July 1, 2018 appear to be somewhat inconsistent. The Company in its Rebuttal Case, although noting the uncertainty surrounding whether it would be required to use ARAM or Reverse South Georgia methodology, proposed to flow-back the Protected EDITs assuming that its use of ARAM will be allowed. To the extent that the Company was wrong in its assumptions it would take necessary corrective action. In fact, the Company stated it had already begun amortizing the Protected EDITs on its books in January 1, 2018. The Company noted that for the Unprotected EDITs, which do not have mandated flow-through treatment, the Company planned on using a ten-year period but that recovery period was not prescribed.

As part of its Supplemental Rebuttal Case, the Company withdrew its proposal to begin flow-through of the EDITs. In that testimony, the Company noted that the application of the Tax Act is even more complicated than predicted and that Emera has less confidence that its early estimates would prove accurate. The Company noted that a violation of the IRS's Normalization Rules could result in significant consequences for Emera. Chahley/Davoren/Therrien Supp. Reb. Test at 2.

In its Brief, the Company again emphasizes the perils of a normalization violation and criticizes the Staff's proposal to flow-through the Unprotected EDITs even though that portion of the EDITs do not have any mandated treatment. Emera argues that given the severe consequences of a normalization violation, it would not be prudent to adjust rates on July 1, 2018 for any EDITs, whether they relate to Protected or Unprotected assets. Emera strongly urges the Commission to rule that all the EDIT tax savings be deferred at least until the Company and its tax advisors can be sure that their recommendation for flowing back tax savings complies with the IRS Normalization Rules. Emera Brief at 73-74.

Despite Emera's uncertainty surrounding the appropriate approach to the amortization of the EDITs, the Company acknowledged at the hearing that it had in fact begun amortizing both the Protected and Unprotected EDITs for purposes of calculating its earnings for the first six months of the year. 05/03/18 Tr. at 83. In response to an oral data request posed by the Bench at the hearing, the Company stated that by June 30, 2018 it will have amortized $253,290 from the Protected class of EDITs and $445,653 from the Unprotected class of EDITs. ODR-008-002.

The Company's amortization of these EDITs seems contrary to its claims of uncertainty surrounding the EDIT amortization and is certainly contrary to the Commission's objective that these EDITs which represent ratepayer funding for the payment of tax liabilities that will no longer occur, be returned to ratepayers. The Commission thus orders the Company to return such amortizations to the appropriate

EDIT regulatory liability accounts. We will review the EDIT issue this fall as part of an investigation which looks at several issues left unresolved here. When this issue is looked at as part of that investigation, it may be possible to offset October 2017 storm costs which are approved for recovery in *Emera Maine, Request for Referral of Incremental Storm Restoration Costs, Docket No. 2018-00021 (Docket No. 2018-00021)*. Until such time as ordered by the Commission, the Company should not begin to amortize any of the EDITs related to the TCJA.

c. <u>Savings Related to the January 1, 2018 – June 30, 2018 Time Period</u>

Through our decision above, we have addressed how the EDITs created as a result of the TCJA for the January 1, 2018 – June 30, 2018 period should be addressed. The only questions remaining before the Commission are whether the savings which result from the TCJA's reduction in the tax rate for the January through June period should be the subject to an accounting order and if so, how the resulting deferral should be calculated.

In its Brief, Emera argues that the last time that corporate tax rates were significantly reduced, the Commission took a very different approach and adopted a rule, referred to as Chapter 90, which allowed utilities to either prospectively flow-through the tax savings in their rates or to file a "mini-rate case" so that all tax savings could be reviewed along with all of the utility's costs. In its Brief, the Company argues that the Staff has chosen to take a different path here and has instead suggested that the Commission issue an accounting order to capture the savings retroactively. The Company also argues that it did not have adequate notice of this change in direction.

First, to be clear, it is the Commission, and not the Staff, that has chosen the different path than the one followed by the Commission in 1986. In 1986, the tax changes that were enacted were to take place in stages with the first tax cut not scheduled to take effect until several months after the enactment of the legislation. *Rulemaking, Revenue Adjustment, for Tax Reform Act of 1986 and Decreased Cost of Capital (Chapter 90)*, Docket No. 86-148 Order Adopting Rule and Statement of Factual and Policy Basis (Jan. 30, 1987). In the case of the TCJA, the Commission was faced with a situation where the reduction in the tax rate occurred in one very significant step, from 35% to 21%, and was almost immediate; the tax legislation was signed into law on December 22, 2017 and took effect on January 1, 2018. When faced with these circumstances, the Commission decided to take a different approach than the one employed by the Commission in 1986 and initiated investigations of individual utilities to review the impact of the TCJA and how the tax savings should be reflected in utilities' rates. See, e.g. *Public Utilities Commission, Investigation of the Impact of the Tax Cuts and Jobs Act of 2017 on Central Maine Power Company,* Docket No. 2018-00004, Notice of Investigation (Jan. 11, 2018). Indeed, the separate investigation approach was identified by the Commission back in the 1986 rulemaking procedure as a possible vehicle to address the impact of the tax reductions. *See, Docket No. 86-198, supra.*, at 2.

In the instant case, since Emera Maine was already before the Commission for a rate change, the Commission determined that it would not be necessary to initiate a separate proceeding for it to investigate the impact of the TCJA on Emera. Instead, by way of the Staff's Bench Analysis issued on December 21, 2017 and by way of a Procedural Order issued by the Hearing Examiner on January 11, 2018, the Company was advised of the issues to be addressed and was provided with an opportunity to address such issues. The Company has addressed these issues through several rebuttal filings, at the hearing and in its Brief. It is unclear as to what further notice Emera could have been given of this issue. It is also unclear how any additional prior notice could have impacted Emera's conduct. Quite simply, Congress enacted a significant reduction in the corporate tax rate and that change reduced Emera's expenses.

The Company argues extensively in its Brief that the Commission cannot capture the savings for the January – June time period because such action would constitute retroactive single-issue ratemaking. Emera Brief at 57. The Commission does not dispute the fact that the creation of a regulatory liability for the tax expense savings for the January – June period would be rearward looking, or retroactive, and would also be single-issue. The Commission can, however, where circumstances warrant, order the deferral of costs or savings for later rate treatment through the issuance of an accounting order. *See* 35-A M.R.S. § 502; Public *Advocate v. Public Utilities* Commission, 1998 ME 218, 718 A. 2d 201; and *Public Utilities Commission, Investigation of Stranded Cost Recovery Transmission and Distribution Utility Revenue Requirements and Rate Design of Bangor Hydro-Electric Company* Docket No. 1997-00596, Accounting Order (Sept. 8, 1999). Indeed, Emera Maine has taken advantage of such authority when faced with an unexpected increase in expenses and one such request is currently pending before the Commission in *Docket No. 2018-00021*. The real question before the Commission then is not whether the Commission can issue an accounting order but whether an accounting order should be issued based on the standards established by the Commission governing such orders.

The Commission has held that to be eligible for accounting order treatment the cost item must be extraordinary which has been further defined as unusual and sufficiently large that absent a deferral the item would unduly impact earnings. *Fox Islands Electric Cooperative, Request for an Accounting Order for Incurring Extraordinary Costs in Dealing with Storm Damage*, Docket No. 2008-00048, Accounting Order (Mar. 27, 2008) and *Northern Utilities, Inc., Proposed Environmental Response Cost Recovery*, Docket No. 1996-00678, Order Approving Stipulation (April 28, 1997) (*Northern Utilities, Docket No. 1996-00678*).

In this case, the Company has argued that the tax change is not an unusual event. Based on the record before us it seems very clear the TCJA is, in fact, an unusual event. The last time that the federal government reduced the corperate tax rate by anything approaching the magnitude of the TCJA, was approximately 32 years ago. The TCJA's impact on earnings was also clearly large: impacting Emera's revenue requirement in the range of $3.5 to $4.0 million annually. The Company argues that the Commission's issuance of an accounting order for the TCJA would violate the regulatory bargain between the Commission and T&D utilities which allows for the granting of accounting orders for storms but not for other situations. The Commission is not aware of such a regulatory bargain nor does it believe that its authority to issue accounting order is limited. In addition, the Commission does not believe its authority to issue accounting orders is limited to events of relatively short periods of time as the

Company suggests. In support of this conclusion, we would note that the Commission granted Bangor Hydro-Electric Company an accounting order to defer and collect from ratepayers the incremental costs associated with implementing electric restructuring. *Docket No. 1997-00596*, supra. See also *Northern Utilities*, *1996-00678 supra*., (granting an accounting order for environmental clean-up costs). The Company also argues that the Commission did not issue an accounting order in the Northern Utilities recently completed rate case for the time period between TCJA enactment and the time new rates went into effect. *See Northern Utilities, Docket No. 2017-00065*. The facts of the *Northern Utilities, Docket No. 2017-00065* case and this case are distinguishable, however, since in the Northern case, TCJA actually was enacted after hearings were held and Northern did not have an opportunity to address the accounting order in its testimony or at the hearing. In addition, the time period between TCJA enactment and when new rates went into effect was extremely short and thus the impact was not extraordinary.

For the reasons set forth above then, we find that an accounting order should be issued here to defer, or capture, the savings resulting from the TCJA tax rate reduction from 35% to 21% during the period of January 1, 2018 to June 30, 2018. The question then becomes how such savings should be calculated.

The OPA and Staff both estimate the January 1, 2018 – June 30, 2018 tax savings in a similar way. Both parties contend that the tax savings from this period should be returned to ratepayers in this proceeding, and proposed recalculating the return on equity from the last rate case using the new tax rate in the gross-up calculation, and comparing that amount to the return calculated using the 35% tax rate in effect at that time. OPA Brief at 21, Reply B.A. at 3. The Staff calculated a total reduction of $3,121,768 (half, $1,560,884, applied to the first six months of 2018). Corr. B.A. at 3-4. The OPA calculated savings attributable to the reduced tax rate of $3,427,887 (half, $1,713,939, applied to the first six months of 2018). Morgan Sur. Test. at LKM-1.

The Company argues that the pre-July 1, 2018 tax savings cannot be calculated until after July 1st, so as to be reflective of actual revenue and expenses incurred during the first half of 2018. Emera asserts that the tax savings, if based on the allowed return from the last rate proceeding as proposed by the OPA and Staff will be overstated since it has not earned its allowable return during the first half of the year. Emera Brief at 66-67.

The Commission agrees that it is reasonable to estimate the January – June 2018 tax savings by recalculating the return included in the last rate case, as proposed by the OPA and Staff, since such methodology captures the difference from what was allowed in rates based on the old tax rate when compared to the new tax rate. The methodology is also relatively straight forward and efficient and would avoid a battle on what the Company's earnings were for the first half of 2018 which would likely arise under the Company's virtual closing of its books in order to determine earnings for the first six months of the calendar year. In reaching our conclusion here, the Commission would also note that the test for the issuance of an accounting order has always been whether the cost, or savings, would have a significant impact on earnings and not whether the Company is in an over or under-earnings situation. *Northern Utilities*, supra. As such, the amount that can be deferred is not capped or limited by the amount that would put the utilities earnings either above or below its previously authorized ROE.

The Company argues that the Staff/OPA approach we now adopt is extraordinary. It should be recognized, however, that this same approach, or one very similar, has been adopted by other regulatory commissions in addressing how to incorporate the savings created by the TCJA in rates. *See In the Matter of the Investigation of Federal Tax Reform Impacts on Public Utility Revenue Requirements*, (Montana) Docket No. 2017.12.94, Notice of Commission Action (Dec. 29, 2017); *Investigation to Determine Rate Effects of Federal and State Corporate Tax Reductions,* (N.H.) Order No. 26.096 (Jan. 3, 2018); *Tennessee Public Utility Commission Investigation of Impacts of Federal Tax Reform on the Public Utilities Revenue Requirements,* (Tennessee) Docket No. 18-00001, Order Opening an Investigation and Requiring Deferred Accounting Treatment (Feb. 6, 2018).

It appears that the difference between the OPA's and Staff's calculation is a result of the OPA including the impact of state income tax on the total combined tax rate, while Staff's calculation did not. The Commission finds the OPA's calculation to be more precise, and therefore, accepts $1,713,939 as the amount of tax savings for the first six months of 2018 to be reflected in a regulatory liability account to be established as of July 1, 2018. This regulatory account shall accrue carrying costs at the Company's weighted average cost of capital and should be considered to be available to offset any storm costs which are approved for recovery in *Docket No. 2018-00021*.

IV. COST OF CAPITAL

A. <u>Positions of the Parties</u>

1. <u>Emera Maine</u>

In its Brief, Emera argues that the Commission should adopt a 9.50% after-tax ROE, the same base ROE as the Commission had determined in the Company's last rate case without the downward management efficiency adjustment. Emera states that its cost of capital expert recommended an ROE of 10.20% in his initial and rebuttal testimony and had determined that overall market conditions had not changed significantly since the last rate case was decided. Emera Brief at 49. The Company proposed a 9.50% ROE in this case in the hope of minimizing the dispute and associated time and cost to the parties in addressing with this issue. *Id*.

Emera notes that in February 2018, the Commission determined that the allowed ROE for Northern Utilities should be 9.50% and that Staff has given no consideration to this fact or to which utility was a riskier investment when recommending a lower ROE for Emera. *Id*. at 50. Emera argues that Northern has multiple mechanisms that mitigate risk, including a capital tracker mechanism for its cast iron replacement program. *Id*. Further, Emera observes that Northern has a fixed customer charge for residential customers of $25.06 per month as compared to $7.54 per month for BHD and $6.59 per month for MPD. Emera asserts that this causes Northern to recover three to four times more revenue per customer through fixed charges than does Emera. *Id*. at 51.

The Company argues that the recommendation of its cost of capital expert is based on a more comprehensive analysis than Staff's analysis and better incorporates future market conditions including expected future increases in interest rates by the Federal Reserve. *Id*. at 52. Finally, the Company argues that additional factors should be considered in determining an allowed ROE, including the following: Emera does not have other risk mitigating mechanisms such as revenue decoupling that are used by some utilities; Emera has a sizable capital investment program; Emera is small compared to its proxy group with a limited service territory and less geographic, economic and regulatory diversity; the recent decline in utility stock prices suggests that recent federal income tax changes have caused investors to invest in companies that are not utilities; and, the concerns expressed by credit rating agencies about the impact of the TCJA on utility cash flow. *Id*. at 51.

In his Rebuttal Testimony, the Company's cost of capital witness, John Perkins, updated his initial testimony to incorporate more recent market data and used a slightly revised proxy group of 24 comparable electric utilities. He then estimated Emera's cost of common equity using: discounted cash flow models (DCF, constant growth and multi-stage growth); capital asset pricing models (CAPM, traditional and empirical); risk premium models (bond yield plus premium and predicted risk premium); and an expected earnings approach. Emera argues that this is a more comprehensive analysis and that models such as the bond yield plus risk premium are particularly relevant considering the historically low level of current Treasury yields. Perkins Reb. Test. at 51 and Emera Brief at 52.

Mr. Perkins calculated his DCF results using growth rates based on long-term earnings per share growth projections from securities analysts.[13] Mr. Perkins developed his constant growth DCF range based on the lowest of the three projections (referred to by Perkins as Mean Low), the highest of the three projections (Mean High) and the average of the three growth projections (Mean). Perkins Reb. Test. at 39-40. He then gives the Mean Low DCF results no weight in his analysis, noting that the results are below any reasonable estimate of the Company's cost of equity and that only seven of the awarded ROEs since 1980 were below 9.00%. *Id*. at 40. The constant growth DCF based ROE range developed by Mr. Perkins, which includes a flotation cost adjustment of 0.11% and disregards his Mean Low analysis, is 8.30% to 9.32%. *Id*. Mr. Perkins also uses a multi-stage growth DCF approach and develops an ROE range, which includes the Mean Low results, of 8.65% to 10.01%. *Id*. at 45.

In his Rebuttal, Mr. Perkins also provides CAPM and Empirical Capital Asset Pricing Model (ECAPM)[14] analyses that indicate an ROE range of 8.85% to 13.49%, a Bond Risk Premium analysis that indicates an ROE range, excluding flotation costs, of

---

[13] Long-term growth estimates from Zacks consensus long-term earnings growth, First Call consensus long-term growth estimates and Value Line long-term growth estimates. Perkins Reb. Test. at 39.

[14] The ECAPM model corrects for the empirical observation that the securities market line has a shallower slope than would be indicated in the normal CAPM model. The securities market line is a graphic representation of the capital asset pricing model. It displays the expected rate of return of an individual security as a function of systematic, non-diversifiable ("market") risk.

9.95% to 10.25% and a Predictive Risk Premium Model (PRPM) that indicates an ROE range of 9.58% to 11.01%. Perkins Reb. Test. at 50-55.

2. Office of the Public Advocate

The OPA did not submit cost of equity testimony in this case. The OPA states in its Brief that it supports an 8.97% overall rate of return for Emera as set forth in the Reply Bench Analysis. OPA Brief at 2, FN 3. This weighted average cost of capital reflects an equity ratio of 49%, cost of long-term and short-term debt as filed by the Company and an after-tax ROE of 9.35%. The OPA further recommends that the Commission apply a downward management efficiency adjustment. The revenue requirement calculations in the OPA's Brief are based on an overall rate of return of 8.97%. *Id.*

3. Commission Staff

In its Bench Analysis, the Staff recommended an ROE of 9.00%. In arriving at its recommendation, the Staff developed a proxy group of electric utilities that consisted of 20 companies and used a DCF analysis, both a constant-growth model and a two-stage growth model, and a CAPM calculation as a check on the DCF results. Staff developed a DCF range of 7.20% to 9.43% and a CAPM range of 8.90% to 10.70%. Staff did not dispute the Company's inclusion of a flotation cost adjustment, its recommended capital structure or the calculation of the costs associated with the long-term debt, short-term debt or preferred stock components of Emera's capital structure.

In its Reply Bench Analysis, the Staff recommended an after-tax base ROE of 9.35%, which included a flotation cost adjustment. In arriving at its recommendation, the Staff developed a proxy group of electric utilities that consisted of 22 companies and used a DCF analysis, both a constant-growth model and a two-stage growth model, and a CAPM calculation as a check on the DCF results. Staff developed a DCF range of 7.70% to 10.64% and a CAPM range of 9.04% to 10.81%. In its DCF analysis, for a future growth estimate Staff used 5.18%, the average of the growth rates in earnings per share projected by securities analysts who follow the stock of the proxy group companies as of March 26, 2018. As noted in the Bench Analysis and Reply Bench Analysis, Staff did not disagree with the Company's inclusion of a flotation cost adjustment, its recommended capital structure or the calculation of the cost of the short-term debt, long-term debt or preferred stock components of Emera's capital structure.

B. The Hope-Bluefield Standard

Two United States Supreme Court decisions of more than 70 years ago, known as the *Bluefield* and *Hope* cases, provide the standards for measuring the reasonableness of a utility's allowed ROE. Taken together, the *Hope-Bluefield* decisions establish that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made…on investments in other business undertakings which are attended by corresponding risks and uncertainties…The

> return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties...

Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

Additionally, the idea of associating the allowed return to a common equity owner with those available from other companies of comparable risk was established in the *Hope* decision:

> [T]he return to the equity owner should be commensurate with the return on investment in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

Thus, the practice of determining an appropriate ROE for a company that is not publicly traded such as Emera Maine is one that involves developing a comparable group of companies, for which market-based information is available, that are in the same business and that present similar financial risks. The *Hope-Bluefield* standard has long served as the benchmark against which this Commission measures an appropriate ROE.

C. Discussion and Decision

1. Impact of the TCJA

As an initial matter, the Company has proposed that post-July 1, 2018 savings associated with the reduction in the federal corporate income tax rate from 35% to 21% be “collected in a regulatory liability account to be used to stabilize future rates.” Emera Brief at 70. Thus, in computing the pre-tax WACC used for calculating a return on its rate base, Emera has grossed-up the cost of common equity assuming a federal income tax rate of 35% rather than 21%, which results in a pre-tax WACC of 10.46% as shown in Figure IV.1.

Figure IV.1

Emera Maine			
Computation of Weighted Average Cost of Capital			
			After-tax Weighted
Capital Structure	**Ratios**	**Cost**	**Ave. Cost**
Long-Term Debt	47.03%	5.18%	2.44%
Short-Term Debt	3.91%	4.15%	0.16%
Preferred Stock	0.06%	7.00%	0.00%
Common Stock	49.00%	9.50%	4.65%
	100.00%		7.25%
Pre-tax Weighted Average Cost of Equity			7.86%
Pre-Tax Weighted Average Cost of Capital			**10.46%**
Weighted Average Cost of Debt			2.60%
Pre-tax Weighted Average Cost of Equity			7.86%
Total Pre-Tax Weighted Average Cost of Capital			10.46%

Based on an allowed ROE of 9.50%, the reduction in the federal income tax rate reduces pre-tax WACC from 10.46% to 9.05%. Chahley/Davoren/Therrien Reb. Test. at 51. As explained in Section IV (C) (2), the Commission determines that ratepayers should receive the benefit of the lower federal income tax when new rates go into effect on July 1. Accordingly, our calculations of pre-tax WACC reflect a 21% federal income tax rate.

2. Capital Structure and Cost of Debt

As noted, there are several issues related to the cost of capital about which there is no dispute. Emera has proposed a capital structure that includes 49% common equity, 0.06% preferred equity, 3.91% short-term debt and 47.03% long-term debt. The cost of the preferred equity is based on the 7.00% dividend rate. The cost of the short-term debt is derived based on a thirteen-month average usage of the Emera revolving credit facility, an interest rate based on a forecasted LIBOR rate plus 1.25% and related fees. The cost of long-term debt is 5.18% which is based on the weighted cost of the Company's outstanding debt issuances. Chahley/Davoren/Therrien Test. at 7. The Commission finds that these ratios, and the costs associated with these components of the capital structure, are reasonable.

3. Return on Equity

The cost of equity analyses in the record are based on a group of electric utilities that present risk that is comparable to Emera Maine. Although there are differences in the final proxy groups used by the Company and the Staff, there is substantial agreement as 22 companies are included in both proxy groups. This sample size is large enough and consistent enough to allow a meaningful analysis of market returns. As noted above, the Company recommends an allowed ROE of 9.50% and the Staff has recommended a base ROE of 9.35%. The OPA supports the overall rate of return recommended in the Staff's Reply Bench Analysis that reflects a 9.35% ROE. Emera's cost of capital witness has submitted testimony that recommends a 10.20% ROE.

As has long been our practice, the Commission relies on the DCF methodology and results to indicate an appropriate ROE and uses CAPM results as a check on the DCF results. *Investigation of Central Maine Power Company, Company's Revenue Requirements and Rate Design (Phase II)*, Docket No. 1997-00580, Order, (January 19, 2000) (*Docket No. 1997-00580)*. The Commission's reliance on the DCF market-oriented approach to determine the common-equity cost for the Company is consistent with the *Hope-Bluefield* standard in that it incorporates the equity returns that investors currently expect to receive from investing in companies with risks similar to Emera Maine. Emera suggests that it requires more robust returns because investors are concerned about the negative impact on utility stocks of the recent tax act and expected interest rate increases which create uncertainties the DCF models do not capture. Emera Brief at 51-52. As the models used are market-based and incorporate current market prices and expectations, they reflect the investment community's response to all of the expectations in the marketplace. The Commission is cognizant of current equity market conditions, indications and expectations regarding interest rates and the characteristics of different analytical tools used to estimate a company's cost of equity in a rate making proceeding and continues to have confidence in the DCF methodology.

In his Rebuttal Testimony, Mr. Perkins updated his DCF analysis to reflect market data as of December 29, 2017. The constant growth DCF based ROE range developed by Mr. Perkins, which includes a flotation cost adjustment of 0.11% and disregards his Mean Low analysis, is 8.30% to 9.32%. As shown in Figure IV.2 below, if the Mean Low results are included, the ROE range is 7.46% to 9.32%.

Figure IV.2

	Perkins DCF Analysis		
December 29, 2017	Low	High	Mean
Constant Growth DCF Model	7.46%	9.32%	8.39%
Multi-Stage DCF Model	8.65%	10.01%	9.33%

As presented in the Staff's Reply Bench Analysis, reflecting market data as of March 26, 2018, the DCF analytical model produces an indicated ROE range of 7.70% to 10.64% as shown in Figure IV.3 below. The Staff's analysis does not include a flotation cost adjustment.

Figure IV.3

	Staff DCF Analysis		
March 26, 2018	Low	High	Mean
Constant Growth DCF Model	7.70%	10.55%	9.13%
Two-Step DCF Model	7.77%	10.64%	9.21%

Therefore, the indicated ROE supported by the DCF evidence ranges from a low of 7.46% to a high of 10.64%. As shown, the mid-points of the individual model results are largely in the low-9% range.

The Company and the Staff also provided the results of CAPM analyses which we use as a check to the DCF results. The results of Staff's CAPM analysis indicate an ROE range of 9.04% to 10.81%. Reply B.A. at 12. In his Rebuttal Testimony, Mr. Perkins updated his CAPM results to reflect adjustments to his proxy group and more recent market information. Consistent with the Commission's preference as indicated in *Docket No. 1997-00580*, we consider the CAPM results that are based on current Treasury rates rather than a forecast of interest rates. Mr. Perkins's CAPM results based on current Treasury rates indicate an ROE range of 8.85% to 10.81%. Perkins Reb. Test. at 50. The CAPM results are summarized in Figure IV.4 below.

Figure IV.4

	Treasury Rate	Indicated ROE Range
Perkins CAPM Results-Current Treasury Rate	2.77%	8.85% to 11.20%
Staff CAPM Results-Current Treasury Rate	3.12%	9.04% to 10.81%

As noted previously, the Commission's practice is to primarily rely on the DCF methodology results and to use the CAPM results as a check on the reasonableness of the DCF results. The analyses in this case indicate the ROE could reasonably fall within the range of 8% to 10%. The Staff's DCF analyses produce mean ROE results, without the addition of a flotation cost adjustment, of 9.13% and 9.21%, a range that is confirmed by Mr. Perkin's multi-stage result, which includes a flotation cost adjustment, of 9.33%. The CAPM results do not call into question the reasonableness of the DCF results and would not cause the Commission to deviate from our reliance on the DCF methodology, as the low end of the CAPM analyses is approximately 9%.

The Company has recommended an upward adjustment of 11 basis points to the awarded ROE to reflect the costs associated with the issuance of common stock. Perkins Reb. Test. at 57. As noted in the Bench Analysis, the Commission has permitted a flotation cost adjustment in prior rate cases and the Staff and OPA do not dispute the inclusion of the flotation cost adjustment as calculated by Mr. Perkins. We find that the flotation cost adjustment of 11 basis points is reasonable.

The DCF analyses produce a mean ROE within the range of 9.15% to 9.25% without a flotation cost adjustment, and 9.33% including the flotation cost adjustment. The overall ROE as indicated by the DCF analysis is within a much broader range, from mid-7% to mid-10%. We do not find that Emera Maine presents an unusually large deviation from the risk profile represented in the proxy group and the CAPM analyses does not support a deviation from relying on the DCF results. Thus, the Commission finds the appropriate cost of equity for Emera Maine to be 9.35%. As discussed in Section V, the Commission does not find that a reduction in the allowed ROE to reflect management in adequacy or in efficiency is warranted at this time.

Finally, as noted, Emera urges the Commission to give consideration to the fact that in February 2018 the Commission determined that the allowed ROE for Northern Utilities should be 9.50%. *Northern Utilities, Docket No. 2017-00065* at 5-13. Emera points to several mechanisms that mitigate risk for Northern, including a capital tracker mechanism for its cast iron replacement program, a cost of gas factor that allows Northern to pass through to customers the cost natural gas purchased on behalf of customers and a higher monthly fixed customer charge for certain of Northern's residential customers. Emera's reliance on the cost of equity determined in the Northern Utilities rate case is misplaced. The Northern ROE was determined based on the analyses in the record in that case, which were done at a different time, with a different proxy group, with respect to a different industry, and with different market data and expectations. As explained, the Commission bases its determination of an appropriate ROE for Emera on the evidence and analyses in this record.

4. <u>Weighted Average Cost of Capital</u>

Reflecting these determinations, the weighted average cost of capital is 8.97% for Emera Maine as shown in Figure IV.5 below. This calculation combines an ROE of 9.35%, the capital structure proposed by the Company and the cost associated with each of the other components of the capital structure, and reflects a federal tax rate of 21%.

Figure IV.5

Emera Maine			
Computation of Weighted Average Cost of Capital			
			After-tax Weighted
Capital Structure	Ratios	Cost	Ave. Cost
Long-Term Debt	47.03%	5.18%	2.44%
Short-Term Debt	3.91%	4.15%	0.16%
Preferred Stock	0.06%	7.00%	0.00%
Common Stock	49.00%	9.35%	4.58%
	100.00%		7.18%
Pre-tax Weighted Average Cost of Equity			6.37%
Pre-Tax Weighted Average Cost of Capital			**8.97%**
Weighted Average Cost of Debt			2.60%
Pre-tax Weighted Average Cost of Equity			6.37%
Total Pre-Tax Weighted Average Cost of Capital			8.97%

V. MANAGEMENT EFFICIENCY ISSUES

A. Background

As part of its rate request in Docket No. 2013-00443, the Company initially estimated the cost for a new customer billing system, or "CIS," for its Bangor Hydro District (BHD) to be approximately $17.2 million. Over the course of that proceeding, the Company increased its estimate to $18.8 million and then increased it once again to $19.6 million. The parties included the $19.6 million estimate in the stipulation that concluded the proceeding. The "in-service" date for CIS also shifted over the course of the proceeding, from an initial estimate of May 2014, to the estimate included in the stipulation resolving the case. *Emera Maine, Proposed Increase in Rates (Bangor Hydro and Maine Public Districts)*, Docket No. 2013-00443, Order Approving Stipulation (June 30, 2014).

In the next Emera Maine rate case, initiated by the Company in Docket No. 2015-00360, the Company stated that when it entered into the stipulation in the prior proceeding, the estimated cost for CIS was actually $23.3 million, and not the $19.6 million specified in the stipulation. In addition, the Company stated that the actual final cost of CIS implementation was $30.9 million, with an actual in-service date of June 2015. Subsequent to the Company's implementation of CIS, the Commission's

Consumer Assistance and Safety Division (CASD) began to receive complaints from customers about billing errors. CASD had several discussions with the Company about these issues, which were, apparently, the result of CIS implementation problems. Among the CIS issues discovered by the CASD were a failure to produce or send bills; improper bill dates, including erroneous due dates; one-time fees being charged more than once; and some customers of competitive electricity providers being double-charged for state taxes. The CIS billing issues were reflected in the Company's "Bill Error" service quality index (SQI) metric for 2015: the SQI benchmark for bill errors is 0.04%; the Company's actual bill error rate for BHD was 1.69%.

During the period encompassed by the rate cases, the Company faced other customer service issues, and the CASD had numerous discussions with the Company regarding:

- The Company's failure to issue refunds to customers of People's Power and Gas (People's) for improper charges by People's, despite the Commission forwarding to Emera Maine the security payment People's had placed with the Commission.

- The Company's failure to respond to Commission requests for information regarding the status of the refunds for the People's overcharges.

- A Company decision to unbundle customer charges (stranded costs and conservation) on customer bills prior to requesting a waiver of the Commission's Rules, and also significantly overstating the costs to re-bundle such charges.

- The Company's inability to stop billing customers for Competitive Electricity Provider (CEP) charges after customers had discontinued service with a particular CEP in contravention to the requirements of Chapter 322 § 3(E) of the Commission's Rules.

- The inability of the Company to identify customer-owned private lines for purposes of calculating which portion of storm restoration work done by Emera was attributable to such customers, which resulted in Emera providing refunds to all customers billed for such service.

- Poor performance by the Company for the "Business Calls Answered in 30 Seconds" and "Service Order Timeliness" SQI metrics.

In addition to these customer service and billing related issues, information presented to the Commission in *Maine Public Utilities Commission, Commission Initiated Investigation Into Emera Maine's Transmission Maintenance and Planning Practices,* Docket No. 2015-00161, raised concerns regarding the reliability of the Company's transmission and distribution (T&D) system; concerns which were supported by poor performance results in the Company's System Average Interruption Frequency Index (SAIFI).

Based on all of these concerns, the Commission initiated a management audit of the Company. *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket No. 2015-00360, Order Initiating Management Audit (Apr. 13, 2016). In its Order Initiating Management Audit, the Commission stated that the purpose of the audit was to determine whether:

1. The Company's CIS System (Phase I) was planned and managed in a way that the project would come in as scheduled, on budget and in a manner that ensured that the CIS project delivered the capabilities and functionalities which would maximize ratepayer value.

2. The Company's credit and collections and customer service functions are being managed and operated in an effective, prudent and efficient manner; and

3. Whether Emera Maine's management and operation of its T&D system is being done in a manner that is effective, prudent and efficient and in a manner that ensures that its customers receive reliable service in accordance with reasonable utility management practices.

Id. at 3.

After issuing its Order Initiating Audit, the Commission released a Request for Proposals (RFP), seeking a qualified consultant to conduct the audit, and selected Liberty Consulting Group (Liberty) to perform the audit. Liberty provided its report to the Commission on August 8, 2016. *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket No. 2015-00360, Final Report on an Audit of Emera Maine's Management Practices, Customer Information System, and Service Quality (Aug. 8, 2016) (Liberty Report). In its report, Liberty reached twenty-one separate conclusions regarding customer service and made ten discrete recommendations for improvement by the Company. Liberty Report at III-26 to III-41. In sum, Liberty concluded that the Company's overall customer service performance was weak, that the Company failed to adequately staff its frontline customer service, had poor call answering performance, poor customer satisfaction, and poor employee engagement. *Id.* at I-4. Many of Liberty's recommendations centered around improving staffing levels, improving internal processes, and updating and consolidating its business plans. *Id.* at III-37 to III-41.

Liberty also found that the Company failed to adhere to a reasonable inspection regime for roadside and right-of-way inspections in 2014 and 2015 and had conducted no visual inspections of its distribution plant in the MPD since at least 2011. *Id* at 2. These failures, according to Liberty, "violate good utility practice for promoting reliability." *Id.* In addition, Liberty expressed concern with the Company's seeming acceptance of poor reliability performance. *Id.*

With regard to the CIS project, Liberty found a management team with inadequate oversight and a lack of rigor, stability and experience to implement the project which led to increased costs and delays. *Liberty Report* at I-5. Because of the delays, Liberty found that the Company "went-live" on CIS before the system was fully functional, necessitating that implementation work continue after the system was operational. *Id.* at I-6. Thus, the Company ended up with a system that was not fully functional, over one-third over-budget, eighteen months late, and plagued with system issues. *Id.* at I-4.

In its Order in Docket No. 2015-00360, the Commission found that the Company had failed, over an extended period, to meet even the lowest of standards with regard to call center performance. *Docket No. 2015-00360*, Order – Part II at 49. The Commission also found that the Company's credit and collections practices were unreasonable. *Id.* at 50. With respect to inspections, the Commission found that, while the Company appeared to have an acceptable plan to address the missed inspections from 2014 and 2015, its inspection failures were "not a sound management practice." *Id.* at 33.

After examining the Liberty Report's analysis of the practices of the Company's management, an analysis the Commission found to be credible, and the testimony of the Company's witnesses, the Commission found that the Company's management did not act in a prudent manner with regard to CIS implementation. *Id.* at 63-69. Having made this finding, the Commission then determined the impact of such imprudence. The Commission recognized that while this was, necessarily, an imprecise analysis, the Commission found that such imprecision did not excuse the imprudent conduct. *Id.* at 70. Ultimately, the Commission relied on Liberty's analysis of the harm caused by the Company's imprudent conduct, and ordered a disallowance of nearly $2.5 million of the Company's CIS investment. In addition to this disallowance, the Commission reduced the base ROE for Emera Maine by 50 basis points to reflect the inefficiency of management as evidenced by the Company's failure to perform fundamental utility functions reasonably, such as functions related to billing, customer service, and reliability. In the Part II Order, the Commission noted that the management efficiency adjustment would remain in effect until the Company has demonstrated improvement and customer benefits in these areas. *Id.* at 85.

Thus, in this case, the Commission must review the Company's recent management performance and determine the extent to which there have been demonstrable improvements that would support the elimination (or modification) of the management efficiency adjustment. The Company's management performance is discussed in detail below.

B. <u>Customer Service</u>

1. <u>Background and Overview</u>

As noted above, over the past several years, Emera Maine's performance in certain fundamental customer service related areas has been deficient. These include its call center performance, customer service organization and staffing, customer satisfaction, payment and collections/bad debt, and billing.

With respect to call center performance, until 2012, Emera Maine's Bangor Hydro District had consistently been meeting its call answering target, which was to answer 80% of customers calls within 30 seconds.[15] Beginning in mid-2013, BHD began missing the 80/30 monthly target on a fairly consistent basis. Call answering performance for BHD continued to decline in 2014 and, in October and November of that year, only 30% of calls were answered within 30 seconds. On a company-wide annual basis (including both BHD and MPD), in 2014 the Company was answering 64% of calls within 30 seconds and, in 2015, the Company was answering 66% of calls within 30 seconds, with the poorest performance months being May and June of 2015 (the months of CIS go-live). During those months, the performance at the BHD call-center was slightly above 20% of calls within 30 seconds and on a company-wide basis the performance was 40% of calls within 30 seconds.

Another important indicator of call center performance is call abandonment which provides an indication of whether a utility is just missing the 30 second call answering target or is missing the target to such an extent that callers are giving up and abandoning their calls. According to the Liberty Auditors, good utility practice limits abandonment rates to 5 to 10 percent of calls received. In the Audit, Liberty found that Emera Maine had not achieved this standard since 2013. Liberty Report at III-18. For all of these reasons, the Commission found in the prior rate case that the Company's call center performance constituted inadequate service. *Docket No. 2015-00360, supra.* at 83.

In addition to call center performance, the Commission also found in the prior rate case that Emera's performance was inadequate in the area of its meter-to-bill process (billing) as well as in the area regarding collections and bad debt billing. *Id.* at 82. Bill error performance fell below target in June 2015 and remained problematic as Emera management continued to address CIS-related issues. *Id*. at 39, citing Liberty Report at III-28. The Company agreed with Liberty's conclusion that its billing performance was below target levels, but stated that high occurrences of bill errors are common with customer information system implementations and, moreover, that errors were being resolved through a process involving prioritization and a team of internal and external resources. *Id.* at 43.

In this case, the Company has presented testimony in which it details improvements in customer service at Emera since the last rate case. Holyoke / Richardson/Belliveau/Ravin Dir. Test. at 3. The Company indicates that it is exceeding the annual target of 80% of calls answered within 30 seconds, has improved its processes to identify bill errors before they happen, and has improved its credit and collections processes. The Company states that, because it has addressed the shortcomings that the Commission identified in the prior rate case, the management efficiency adjustment imposed in the prior rate case should be removed. *Id*. at 45. Each of the customer service-related areas is discussed below.

[15] The Liberty Auditors indicated that this target was common within the utility industry. 08/15/16 Tr. at 56 (*Docket No. 2015-00360)*.

2. Planning and Strategy

In its direct testimony, the Company stated that its high-level "customer experience" strategy is in effect and continues to evolve. The Company noted that its original goal was to complete a formal five-year strategy and plan in 2016. *Id*. at 10. Notwithstanding that goal, its current approach with respect to "customer experience" appears to be an ongoing, iterative process, and the completion of a formal five-year plan is on hold until certain technology plans are formulated regarding the customer information system in MPD. *Id*. at 10-11.

Staff noted in its Bench Analysis that the lack of an over-arching strategic plan in this area is a concern. Corr. B.A. at 33. Staff noted further concern about the fact that, even though it does not have such a plan, the Company has requested to recover significant costs to implement customer service enhancements. Finally, the Staff noted that that the Company's current position, that technology considerations rather than an over-arching plan are now driving its planning decisions in this area, seems to contradict the position that Company took in the previous rate case. *Id*. at 32-33.

In its Rebuttal Testimony, the Company disagreed with Staff's assertion that the Company had no long-term plan or strategy for its customer experience processes and investments. Holyoke / Richardson / Belliveau / Ravin Reb. Test. at 40. Although there is no written strategy at this point, the Company states that it does have an overarching plan in this area and is working on committing it to a formal written strategy. *Id*. The Company argued that other utilities had not demonstrated that they had long term plans in place and it was, therefore, not fair to criticize Emera for its lack of a plan. *Id*. at 38. The Company argued further that, whether or not there is a long-term strategy, the Company has demonstrated in this case that its service quality is reasonable and adequate and has justified its request for cost recovery for capital projects which will the implemented during the rate effective year. *Id*. at 39.

For the reasons set forth by the Staff in the Bench Analysis, the OPA supports the Staff's proposal that the Commission continue to apply a management efficiency adjustment to the Company's approved ROE. OPA Brief at 6.

The Commission shares the Staff's concern regarding the lack of a formalized strategic plan to guide the Company's customer service improvement efforts and associated investments. Without such a plan, the Company risks making decisions and investments in an ad hoc manner. The Company itself recognized this risk, stating that improvement efforts or initiatives that would require a major investment need to wait until we (the Company) have a bigger picture in focus. Holyoke/Richardson/Belliveau/Ravin Dir. Test. at 11.

3. Call Center Performance

In response to concerns raised in the Liberty Report, Emera Maine indicated that it has re-organized the management and staffing of its call centers as well as its hiring and training practices. Holyoke / Richardson / Belliveau / Ravin Reb. Test. at 17. The Company also stated that it has engaged an independent consultant to help assess training and support for the call center staff and another consultant to look at how the Interactive Voice Recorder (IVR) can be improved to help customers get quicker answers to their questions. *Id*. at 18. The Company claims that as a direct result of these changes, it has moved from 4th quartile to 1st quartile in JD Power's Customer Satisfaction Survey. *Id*. at 14. The Company states further that due to the changes discussed above, since May 2017 it has been consistently performing at levels that exceed 80% of calls answered within 30 seconds, and is tracking to meet its annual target of 80/30 for the foreseeable future. *Id*. at 15-16. Further, the Company states that its call abandonment rate has recently been in the 2%-4% range.

In the Bench Analysis, Staff agreed with the Company that its call answer performance has improved and is tracking in the right direction. Corr. B.A. at 37. However, Staff noted that the Company must meet its calls answered and call abandonment targets on a consistent and sustained basis to demonstrate that performance had improved to the extent necessary to meet the "reasonable and adequate service" standard. *Id*. at 38.

As noted above, the OPA agrees with the Staff's conclusions in the Bench Analysis related to the Company's customer service performance. OPA Brief at 6.

The Commission agrees that the Company's call answer performance is tracking in the right direction. This appears to be due to the deliberate steps Emera has taken to improve in this area, at least in part, in reaction to the Liberty Audit. Based on the information that has been presented in this case, the Commission finds that the Company's call center performance is no longer considered to be inadequate or below reasonable service levels. However, the Commission will continue to monitor the Company's performance in the area to ensure that these improved service levels are sustained.

4. Billing Errors

The Company stated in its testimony that it continues to identify billing issues associated with the CIS implementation, however, as with any CIS implementation, there will be associated bill errors. Holyoke / Richardson / Belliveau / Ravin Dir. Test. at 30. The Company also stated that it has seen a general downward trend in "incidents" overall and that this is consistent with the expectations of a maturing system.[16] *Id*. at 32. The Company noted that, through its creation of a "Billing and Payment Group" to focus on meter to cash functions and by putting a senior manager in charge of these functions, the Company has taken significant steps to proactively manage bill errors, identifying potential bill errors before bills are sent and avoiding bill errors before they happen. *Id*. at 33. The Company also stated that it has also formed a "Bill Quality Assurance Team" to improve the identification of bill errors and that the team "has been successful in identifying issues." *Id*. at 31-34*.*

In its Bench Analysis, Staff disagreed with the Company's assessment of its billing performance. First, Staff disagreed with the Company's position that it is not unusual or concerning that errors continue to be identified two years after CIS

[16] Emera defines a CU "Incident" as any issue identified for resolution in the CU system.

implementation and that the ongoing errors could not be a symptom of a larger problem. Corr. B.A. at 46. Staff also disagreed with the Company's position that it has been successful in identifying errors prior to bills being issued. *Id*. Staff stated that a review of the Company's response to EXM-002-040 shows that the quality assurance processes described in the Company's testimony have identified only one billing error prior to bills being issued. Staff noted that, considering the fact that the Company has experienced 32 billing errors to date, the discovery of one error is not an indication of overall quality assurance. *Id*. at 47.

In its Rebuttal Testimony, the Company acknowledged that the information it had provided on the bill error issue in response to ODR-001-014 contained several significant errors and omissions (making its performance look worse than it was). Holyoke / Richardson / Belliveau / Ravin Reb. Test. at 25. The Company stated that, among other things, one error in the ODR over-reported the total accounts affected by bill errors in 2017 by 30%. *Id*. The Company also stated that its bill error performance has significantly improved since the CIS implementation in 2015.[17] The Company stated that it achieved a total annual bill error rate of 0.15% for 2017, compared to 3.88% in 2016. *Id*. at 29.

Figure V.1

Bill Error Rate Over 10 Years

	2008*	2009*	2010*	2011*	2012*	2013*	2014	2015	2016	2017
Bill Error Rate	0.03%	0.02%	0.33%	0.15%	0.03%	0.21%	0.05%	0.98%	3.88%	0.15%

*Represents Bangor Hydro or Bangor Hydro District performance only

Source of Data: Cust. Exp. Reb. Test. at 29.

Based on the evidence in this case, the Commission finds that, as a result of steps the Company has taken to improve its billing performance since the prior rate case, the Company's billing performance also appears to be trending in the right direction. As shown in Figure V.1 above, the Company's bill error rate in 2017 was 0.15%, which was significantly less than the 2016 bill error rate of 3.88%, and also less than the target level of 0.40% that was in place under BHE's ARP. However, as with the Company's call answering performance, with just one year of reasonable

[17] The "bill error rate" metric was established in BHE's ARP in Docket No. 2001-00410. The target rate for this metric was 0.40% or less. The Bill Error Rate is calculated by dividing the number of erroneous bills issued by the total number of bills issued. The calculation is based upon the number of actual bills regardless of the number of accounts. A bill is considered "erroneous" when the total amount due is incorrect. BHE's ARP expired in 2007, however, BHE and ultimately Emera has continued to report its performance regarding this metric on an annual basis.

performance, one cannot conclude that this improvement will be sustained; thus, the Commission will continue to monitor the Company's performance in this area.

5. Rate Levels and Customer Satisfaction

To ensure that customers would have an opportunity to articulate their concerns about Emera Maine's proposed rate increase, the Commission held public witness hearings in Presque Isle, Orono, and Machias at which 27 individuals testified. At the Orono hearing, a representative from AARP provided comments from its members, and at the Machias hearing, an AARP representative presented a petition signed by 570 members urging the Commission to deny Emera's proposed rate increase. Excerpts from some of this testimony are provided below:

- This is the third rate increase Emera Maine has requested in less than five years. This is unaffordable for most Maine families, especially those living on fixed incomes. I urge the Commission to do the right thing by denying Emera Maine's rate request. (Machias PWH Tr. at 5)

- The third increase in five years is unconscionable. As it is, the electric bill for home service is one third usage and two thirds delivery. Using as little electricity as possible, that two thirds bill still leaves a very high bill. (Machias PWH Tr. at 6)

- A lot of Mainers are on fixed incomes and cannot afford another rate increase. If you [Emera] need more income, think of cutting some unnecessary in-house expenditures and don't keep passing it on to customers. (Orono PWH Tr. at 24)

Virtually all the commenters at the three hearings urged the Commission to deny Emera's proposed rate increase.

In addition to the statements at the public witness hearings, as of June 1, 2018, the Commission had received almost 700 public comments regarding Emera's proposed rate increase, with virtually all recommending that it be denied. The concerns expressed in these comments are similar to those at the public witness hearings, i.e., about Emera's already high electricity rates and recent rate increases. For example:

- My Emera bill has already gone up. I can't hardly afford it now, if it goes up some more I don't know how I can pay for it. I don't think that they should be able to increase in some more (sic). They already get more than they should!!!!!

- I oppose another rate hike. Seems that the electric bill gets higher even though it's just my husband and me at home now. Only thing not going up these days is our income. If Emera got a corporate tax cut last year, why do they need to increase our rates???

- Dear Commissioners, as you well know, the problem people have is raising prices of Electricity in our state. We are afraid if these increases of our electric bills (sic), we would be forced to leave this beautiful state. Please do not allow these rate increases to continue. Thank you for reading this.

As noted by the OPA, “the comments filed in this docket and the testimony presented at the public witness hearing indicate widespread agreement from customers that Emera’s rates … are a serious problem…”. OPA Brief p 5.

In its testimony, the Company touts its improved customer service performance as reported in the most recent JD Power Customer Satisfaction Survey. Holyoke / Richardson / Belliveau / Ravin Dir. Test. at 14. However, notwithstanding the Company’s improved customer service performance, the JD Power survey also indicates overall customer satisfaction with the Company, and particularly with its prices, remains extremely low when compared to other utilities. EXM-002-010, Attachment A.

In contrast, the Company paints a positive picture of its rate levels. The Company describes its ability to maintain just and reasonable rates as “successful”, noting that, in real dollar terms, even with its proposed 12% increase, its residential distribution rates would be less than they were fifteen years ago. Emera Br. at 3. In the Company’s view, this demonstrates a track record of effective management of costs, and successful achievement of rate stability. *Id.* The Company’s positive perspective in this regard, in addition to being at odds with the views of its customers, also conflicts with an analysis presented by the Staff which indicates that, with its proposed rate increase, Emera Maine’s distribution charges for residential customers in the BHD would exceed the average level in the New England region by as much as 19%, and would exceed charges to CMP customers by as much as 65%. Corr. B.A. at 12.

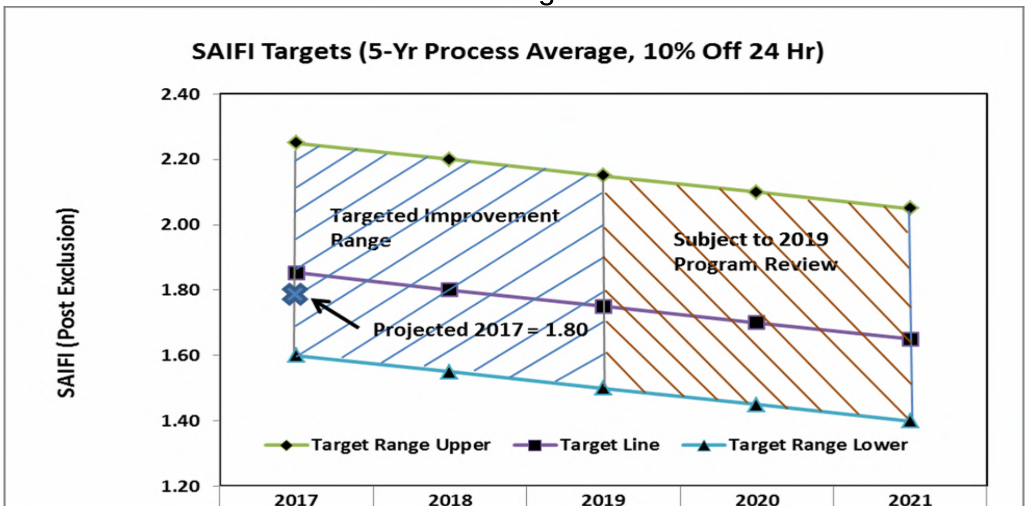
Thus, the Commission finds there to be a certain disconnect between customers views on rate levels and the impact of proposed increases and those of management. We believe this disconnect needs to be addressed by the Company on a going forward basis.

C. Reliability

1. Position of the Parties

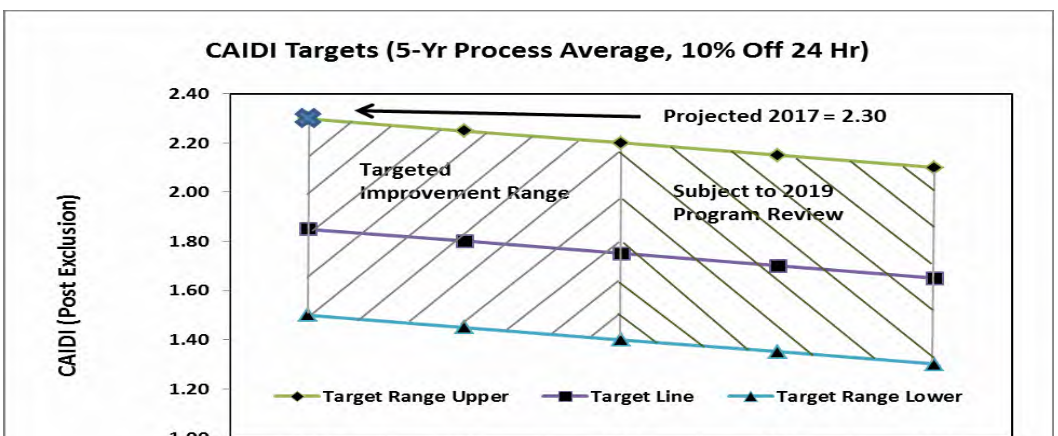
In its filing, Emera proposed to accept many of the findings cited in the Liberty Report related to improving the Company’s reliability performance. Belliveau / Ravin/ Richardson / Holyoke Dir. Test. at 6. In a significant change from its existing practice of maintaining reliability levels from year to year, Emera proposed to target annual incremental Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Frequency Index (SAIFI) improvements. *Id.* at 8. The following Figures illustrate the ranges which Emera proposed. For 2017, the lower band of the range represents a 2.5% improvement from the 2016 target. Emera proposed to continue this improvement trajectory through 2019 premised on approval of including in revenue requirements the reliability-related capital and operating costs proposed in its filing. *Id*.

Figure V.2
SAIFI Targets[18]



	2017	2018	2019	2020	2021
Target Range Upper	2.25	2.20	2.15	2.10	2.05
Target Line	1.85	1.80	1.75	1.70	1.65
Target Range Lower	1.60	1.55	1.50	1.45	1.40

Figure V.3
CAIDI Targets



	2017	2018	2019	2020	2021
Target Range Upper	2.30	2.25	2.20	2.15	2.10
Target Line	1.85	1.80	1.75	1.70	1.65
Target Range Lower	1.50	1.45	1.40	1.35	1.30

[18] Id at RB-7

To achieve this performance improvement, in addition to enhancing its vegetation management program and inspection process, Emera proposed to prioritize capital projects based on a new methodology of ranking reliability projects using an "avoided customer interruption method". This methodology, which assigns a cost per avoided customer interruption ($/ACI), would allow the Company to compare reliability projects in a quantitative way. *Id*. at 18. Regarding inspection programs, Emera described its process for completing missed inspection cycles. *Id*. at 35. Emera also proposed to add several new inspection programs such as ground line pole testing, infrared and ultrasonic inspection programs to better identify issues on their system. *Id*. As noted above, these new programs are expected to cost $224,420 per year. Emera also explained that, due to the volume of make-up inspections as well as changes in labeling identified issues, they were expecting the number of issues identified to increase in the near term. 12/1/17 Tr. at 25.

In its Bench Analysis, Staff expressed support for the steps Emera was making toward improving system reliability. Staff also noted that Emera was at risk of not meeting its targets for SAIFI and CAIDI for the year and concluded that sustained performance improvement was uncertain. Corr. B.A. at 17-18. Staff also raised concerns with the increasing number of identified issues Emera was finding during its inspection processes. *Id*. at 21. Figure V.4 below illustrates the increasing number of open inspection issues at the close of each year. *Id*.

Figure V.4

Distribution Issues Open at End of Year	
Year	**Qty**
2012	1,355
2013	1,571
2014	1,659
2015	1,925
2016	4,606
2017	23,282

Staff proposed that Emera develop a “more robust classification system so that identified problems that may become reliability or safety issues before the next inspection cycle are separately classified and calendared for work.” *Id*. As part of the on-going effort to evaluate the changes Emera is implementing, Staff recommended that Emera be required to file Annual Reliability Reports with the Commission by April 1 of each year that would provide the following service quality and reliability performance information for the prior year:

- Customer Average Interruption Duration Index (CAIDI); System Average Interruption Frequency Index (SAIFI); Feeder Average Interruption Frequency Index (FAIFI) (for circuits that exceed 6.3); Business Calls Answered within 30 seconds; and New Service Installations. This information shall be reported with and without excludable days. For the purposes of determining excludable days, Emera shall use the IEEE 2.5 Beta method on calendar day basis.

- Outage by Cause Code by Service Center; summary of the results under Emera's vegetation management (cycle trim and enhanced trimming) and line inspection programs; age of distribution plant by major plant category.

Id. at 26.

In its Rebuttal Testimony, Emera updated its 2017 reliability metrics to account for more recent data, noting that it had managed to meet its targets for the year. Belliveau / Ravin/ Richardson / Holyoke Reb. Test. at 7. The Company agreed with Staff's recommendation to annually report on the metrics listed in the Bench Analysis. *Id.* at 15. Emera also suggested adding the System Average Interruption Duration Index (SAIDI) metric to the reporting requirements. In its Brief, the Company agrees with Staff's recommendations regarding the inspection process. Emera stated that it would work to develop a more robust classification system for certain issues resulting in more defined timing for addressing issues, and, therefore, less risk associated with those becoming reliability or safety issues. *Id*. at 12. Emera asserts that it will need to retain flexibility for non-safety issues to cost effectively address low priority identified problems. *Id*. at 13.

2. <u>Decision</u>

The evidence in the record shows that Emera Maine has taken positive steps to improve reliability across its system. Although, CAIDI performance in 2017 was worse than it was in 2016, it was within the acceptable level under Emera's new targets. However, the Commission will continue to monitor the Company's reliability performance for continued improvement, as well as to assess whether the target ranges that have been set remain appropriate. Implementing the annual reliability metric reporting, with the information proposed by Staff and as augmented by the Company, will assist in this ongoing monitoring. In the context of this ongoing reporting, other reliability metrics should be considered and added if appropriate, including metrics that can leverage advanced meter data on a customer level.

Emera's position regarding increasing the robustness of the classification of its inspections is also reasonable. The improved inspection processes will aid the Company in maintaining a safe, reliable system. A more robust classification system combined with a better informed reliability program will enable the Company to target the highest priority problems while not losing sight of other less pressing, but significant matters. The Company's inspection reports should also be provided as part of the annual reliability reporting described above.

D. <u>Regulatory Issues</u>

1. <u>Positions of Parties</u>

In its Bench Analysis, the Staff listed a series of issues that may indicate a systemic problem with the management and culture of the Company. These include several examples of failures by Emera Maine to provide adequate support for regulatory processes such as standard offer service and other electricity supply procurement and contracting, as well as in the context of customer billing issues that it seemed to unable to resolve in a timely fashion without the active intervention of the CASD. Corr. B.A. at 97-99. In Staff's view, these ongoing management issues, coupled with other management issues discussed in the Bench Analysis, supported a ROE of 8.75%, which was at the lower end of the reasonable range of ROEs resulting from the Staff's analysis. *Id.*

In its Brief, Emera Maine argues that its management practices are sound. Emera Brief at 5. Emera argues that its Rebuttal Testimony responds to the Bench Analysis extensively, and expresses hope that this testimony will be persuasive that a reduction to ROE for management efficiency is not appropriate. *Id.* at 11. In the Rebuttal Testimony referenced by Emera Maine, the witnesses asserted that the Staff's position is fundamentally flawed because it does not properly balance the Company's positive and negative performance. Richardson/McQuaid/Chahley Reb. Test. at 4. The witnesses also cited to the specific examples provided by Staff that, in Staff's view, were illustrative of an on-going weakness in the support provided by the Company for regulatory activities, noting that these were examples that resulted from a lack of understanding on the Company's part regarding what it was expected to be doing. *Id.* at 6-7. The witnesses noted, further, that the Company will endeavor to minimize such occurrences. *Id*. The Company's testimony also rebutted information provided by Staff in the Bench Analysis regarding the level of the Company's distribution rates compared to other electric distribution companies in New England. *Id*. at 7-10. Finally, the Company argued that it has already been penalized for the shortcomings identified in the last rate case and that the Commission's evaluation of management efficiency in this case should focus only on the period beginning after the order was issued in that case, which was December 2016. *Id.* at 13.

In its Brief, the OPA argues that the Commission should continue to set a reduced ROE because of the Company's inefficient management practices and the inadequacy of the service it provides to customers. OPA Brief at 6. The OPA argues that the Commission's authority to determine reasonable rates allows for consideration of the value of the service provided, as well as customers' ability to pay. *Id*. at 3. OPA argues that, in this case, the ability of Emera's customers to pay the rates it proposes to charge should be carefully considered. OPA argues that there is compelling evidence in the record of the difficulty customers would experience as a result of the Company's proposed rate increase. *Id.* at 4-5.

2. <u>Decision</u>

With respect to the reasonableness of Emera Maine's ongoing support for regulatory activities such as standard offer and other supply solicitation and contracting, the Commission appreciates the Company's expressed desire to modify its processes and to meet reasonable expectations. However, the Commission does not find persuasive that the Company was not, or could not have been, aware of what was expected of it in this regard. These solicitation and contracting processes have been conducted for the past eighteen years, and, to a significant extent, the role (or expected role) of the utilities throughout this period of time has not changed. Moreover, the Commission considers the examples provided by Staff to be just that, examples. The Commission is hopeful that the Company understands this point, and looks forward to stronger support and more positive interactions in the future.

E. Overall Management Efficiency

For the reasons discussed above, the Commission finds that there are signs that Emera Maine is moving in the right direction with respect to carrying out certain fundamental aspects of its business such as call answering, billing, and reliability. This appears to be an early indication that management has taken deliberate and appropriate steps to improve the Company's performance in these areas. The Commission also acknowledges the examples of positive performance in other respects cited by Company witnesses. Policy Panel Reb. Test. at 5-6.

In deciding to impose a management efficiency adjustment to Emera's base ROE in Emera's last rate case, the Commission noted:

> The adjustment to Emera Maine's ROE shall remain in effect until the Company demonstrates to the Commission that its management practices and efficiencies, particularly in the areas of customer service and with respect to the Company's systems maintenance practices, have improved and have provided real benefits to ratepayers. Thus, the Company is not forestalled from returning with a rate case in which they demonstrate that the numerous improvements that management referred to during the course of this case have borne fruit and that the trends in service are in the right direction.
>
> *Docket No. 2015-00360, supra.* at 85.

Based on the information presented in this case, the Commission is satisfied that in the areas of customer service and systems maintenance practice, the Company has made significant improvements in its operations which have in fact, borne fruit. Therefore, the Commission concludes that the rationale for our management efficiency adjustment in *Docket No. 2015-00360* no longer exists. The Commission further finds that with respect to other aspects of the Company's performance which have been raised in this case by the Staff, that there have been sufficient recent improvements to demonstrate that the Company is on the right path and that no additional management efficiency adjustment is warranted at this time.

VI. RATE PLAN AND FOLLOW UP PROCEEDING

A. Positions of the Parties

In its Part II Order in Docket No. 2015-00360, the Commission suggested that Emera consider presenting a multi-year alternative rate plan (ARP) in its next rate case which would provide incentive for improved performance and enhanced earnings. In its initial testimony, the Company stated that it is not in a position to propose a multi-year rate plan at the present time. Specifically, the Company noted the following four areas where it needed to advance its thinking:

1. It wants to be sure that the metrics and targets it uses to define and measure successful service to customers represents the best thinking for today and for the future, versus the past.

2. It wants to be sure that the Company has a solid understanding of what it will take for Emera Maine to meet its customers' current and future expectations, in terms of people, process and technology. On the technology side, in particular, Emera Maine wants to be sure that its plan for the period covered by a multi-year rate plan is solid and is aligned with the expectations of customers, stakeholders and the Commission.

3. It wants to do what it can to support economic growth in its territory and in Maine, and believes that improved rate designs could help.

4. The Company's business model is subject of a number of potential challenges, including but not limited to challenges which lower sales volume, which today is the billing determinant for most of our revenues. If Emera Maine were to propose a multi-year plan, it would need some confidence that sales volumes could be expected to support the revenue requirement or alternatively, propose some form of de-coupling. This is not something the Company has studied in any detail at this point.

Richardson/McQuaid/Chahley Test. at 14-15.

In its Bench Analysis, Staff stated that the reasons put forth by the Company did not preclude consideration or adoption of a rate plan and that issues such as metrics and targets, technology plans, the design of a revenue developing mechanism and the outcomes from a possible future rate design case, could all be considered as part of the rate plan proceeding. Staff recommended that the Commission initiate a Phase II proceeding at the conclusion of the rate case to consider rate plan proposals. Corr. B.A. at 102.

In its Rebuttal Testimony, Emera reiterated that it needs to develop its own thinking in key areas and that the position taken by the Staff demonstrated significant gaps in how the Staff and the Company viewed issues such as customer service, value and rates. Given its opinion that an alternative rate plan must be developed through negotiation and consensus, Emera asserted that negotiating a rate plan would likely be challenging. Richardson/McQuaid/Chahley Reb. Test. at PP-12. In its Brief, Emera urges the Commission not to take the extraordinary step of requiring the Company to file an alternative rate plan or engage in such discussions. Emera Brief at 74. Emera argues that the fact that the Company has had three rate cases since 2013 is not a basis for requiring an ARP, citing lumpy utility investments, flat sales and Emera's efforts to control distribution costs as reasons not to initiate an ARP proceeding. *Id*. at 75. Nevertheless, Emera asserts that it is open to discussing the concept of an alternative rate plan at an appropriate time and suggests that the Commission allow Emera to complete its rate design study in November 2018 and then consider initiating ARP discussions. *Id*.

B. <u>Decision</u>

As we concluded in *Central Maine Power Company, Proposed Increase in Rates*, Docket No. 1992-00345, Order at 130 (Dec. 14, 1993, a multi-year price cap plan can provide a number of potential benefits including:

- Electricity prices continue to be regulated in a comprehensible and predictable way.
- Rate predictability and stability are more likely.
- Regulatory "administration" costs can be reduced allowing the utility to expend more time and resources in managing its operations.
- Risks can be shifted to shareholders and away from ratepayers.
- Exceptional cost management can lead to enhanced profitability for shareholders, thus creating strong incentives for cost minimization.

At this point, the Commission believes that Emera's resources need to be focused on solidifying and continuing the improvements in operations that have been made to date. In addition, the Company needs to be mindful of the concerns of its customers on rate levels and to look at ways it can improve its operations in a manner that do not necessarily result in rate increases. We also recognize that the Company desires to initiate a rate design proceeding in the near future. While the Commission will not order such a proceeding, we believe that rate design should be looked at as a way that might both enhance the Company revenues and benefit customers.

Therefore, the Commission will not immediately initiate a proceeding to develop an alternative rate plan following the conclusion of this rate case. We will, however, initiate a proceeding in the fall to address the issues that were not resolved in this case, specifically:

1. A determination of the amount of the EDITs, Protected and Unprotected, to be returned to ratepayers and how such amounts should be returned or offset against regulatory assets;

2. How the January 1, 2018 – June 30, 2018 TCJA regulatory liability established as a result of decision in this case should be applied to offset any regulatory assets, including a regulatory asset that might be established as a result of a Commission decision in *Docket No. 2018-00021;* and

3. The reconciliation of actual incremental vegetation management costs incurred by the Company and those which have been allowed in rates in this proceeding and how such underages or overages should be reflected in revenue requirements going forward.

Accordingly, it is

O R D E R E D

1. That the revised rate schedules filed by Emera Maine on October 2, 2017 are found to be unjust and unreasonable and are hereby rejected;

2. That Emera Maine should file revised rate schedules for its Bangor Hydro District and for its Maine Public District in accordance with this Order and with an effective date on, or after, July 1, 2018;

3. That the Commission issues an accounting order to create a regulatory liability for the deferral of the savings associated with Tax Cuts and Jobs Act for the period of January 1, 2018 through June 30, 2018 in accordance with the terms of this order; and

4. That pursuant to the provisions of 35-A M.R.S. § 3195, the Commission issues an accounting order for the deferral and reconciliation of differences in the costs, either positive or negative, between the actual incremental amounts associated with the Company's enhanced vegetation program from those which are allowed in rates here, beginning on July 1, 2018 until further ordered by the Commission. This deferral shall accrue carrying costs using the Company's weighted cost of capital established in this proceeding beginning July 1, 2018.

Dated at Hallowell, Maine, this 28th day of June, 2018.

/s/ Harry Lanphear

Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Vannoy
Williamson
Davis

Docket 2017-00198
Order
Exhibit 1, page 1

Emera Maine

Rate Effective Year Distribution Revenue Requirement
Adjusted 2016 Test Year

Line			
1	Total Rate Base	$	292,868,630
2	WACC		8.97%
3	Return on Rate Base		26,270,316
4	Add: Carrying Costs on Swan's Island Acquisition Adjustment		18,435
5			
6	Cost of Service		61,856,480
7	Total Distribution Revenue Requirement	$	88,145,231
8	Rate Year Distribution Revenues at current rates	$	83,691,586
9	Distribution Revenue Shortfall		4,453,645
11	Net Distribution Revenue Shortfall		4,453,645
12	Distribution Rate Increase		**5.32%**

Docket 2017-00198
Order
Exhibit 1, page 2

Emera Maine
Distribution Revenue Requirements
Computation of Weighted Average Cost of Capital

Line	Capital Structure	Ave. Balances	Ratios	Cost		After-tax Weighted Ave. Cost
1	Long-Term Debt	287,694,662	47.03%	5.18%	Cost of Long Term Det	2.44%
2	Short-Term Debt	23,909,833	3.91%	4.15%	Cost of Short Term Del	0.16%
3	Preferred Stock	365,400	0.06%	7.00%		0.00%
4	Common Stock	299,700,000	49.00%	9.35%		4.58%
5		611,669,895	100.00%			7.18%
6		Pre-tax Weighted Average Cost of Equity				6.37%
7		**Pre-Tax Weighted Average Cost of Capital**				**8.97%**
8		Weighted Average Cost of Debt				2.60%
9		Pre-tax Weighted Average Cost of Equity				6.37%
10		Total Pre-Tax Weighted Average Cost of Capital				8.97%

Docket 2017-00198
Order
Exhibit 1, page 3

Emera Maine
Distribution Revenue Requirements
Adjusted 2016 Test Year Rate Base

Line	Distribution Rate Base Components:		Average Rate Base Totals	Test Year Adjustments	Adjusted Test Year Distribution Rate Base
1	Electric Plant in Service	Electric Plant	555,656,739	86,606,788	642,263,527
2	Depreciation Reserve	Depr. Reserve	(207,931,616)	(37,906,683)	(245,838,299)
3	Material & Supplies Inventories	Inventories	2,265,259	-	2,265,259
4	Prepayments	Prepayments	988,853	-	988,853
5	Deferred Low Income Program Costs	Low Income	26,453	(26,453)	0
6	Maine Public District Reg. Asset Pension/Retiree Medical Unrecog. Amts	MPD Pens/PRM Reg Asset	7,188,045	(2,294,481)	4,893,564
7	Regulatory Asset - Loss on Interest Rate Swap Termination	Swap Loss	823,831	(284,070)	539,761
8	Deferred Storm Costs	Def'd Storm Costs	7,393,401	(3,165,090)	4,228,311
9	**Swan's Island Acquisition Adjustment**		-	-	-
10	Swan's Island GIS Regulatory Asset		-	110,130	110,130
11	Regulatory Asset - Swan's Island Revenue Deficiency		-	249,578	249,578
12	Customers' Deposits	Customer Deposits	(3,978,238)	-	(3,978,238)
13	Post-Retiree Medical Liability (PRM)	PRM Liab.	(28,297,307)	(3,604,162)	(31,901,469)
14	Post-Retiree Medical - Unrecognized Losses included in Accumulated Other Comprehensive Loss - Bangor Hydro District	PRM AOCL	(2,755,605)	7,178,500	4,422,895
15	Pension Liability	Pension Liability	(28,969,921)	6,352,977	(22,616,944)
16	Pension - Unrecognized Losses included in Accumulated Other Comprehensive Loss - Bangor Hydro District	Pension AOCL	21,994,149	(3,136,814)	18,857,335
17	SERP Liability - Bangor Hydro District	SERP Liab-BHD	(2,493,692)	159,534	(2,334,158)
18	SERP Liability - Maine Public District	SERP Liab-MPD	(86,380)	12,377	(74,003)
19	SERP - Unrecognized Losses included in Accumulated Other Comprehensive Loss - Bangor Hydro District	SERP AOCL-BHD	476,296	62,240	538,536
20	Contributions in Aid of Construction	CIACs	(699,855)	-	(699,855)
21	Deferred Directors' Fees	Def'd Directors' Fees	(715,865)	397,703	(318,162)
22	Accumulated Deferred Income Taxes	Accum Def'd Income Taxes	(68,010,442)	26,129,126	(41,881,316)
23	Excess Deferred Income Taxes and Unamortized Investment Tax Credits	Excess DIT/ITCs	(424,787)	283,787	(141,001)
24	Deferred Tax Study Regulatory Liability	Def'd Tax Study Reg Liab	(2,677,927)	2,060,046	(617,881)
25	SQI Penalty Regulatory Liability	SQI Penalty Reg Liab	(19,458)	19,458	-
26	Working Capital Allowance	Working Capital	-	2,603,467	2,603,467
27	Pre-2018 ADIT Regulatory Liability from Tax Reform	Tax Reform Reg Liability	-	(38,691,259)	(38,691,259)
28	Non-Labor Regulatory Asset	Regulatory Asset	-	-	-
29	Total Rate Base		$ 249,751,932	$ 43,116,698	$ **292,868,630**

Docket 2017-00198
Order
Exhibit 1, page 4

Emera Maine

Distribution Revenue Requirements
Cost of Service Summary

Line	Net Expenses:		2016 Total Distribution	Test Year Adjustments	Adjusted Test Year Distribution Cost of Service
1	Operation and Maintenance Expense:				
2	Transmission Operation & Maintenance	O&M Expense	(926)		
3	Distribution Operation	O&M Expense	6,326,325		
4	Distribution Maintenance	O&M Expense	10,942,327		
5	Customer and Sales Expenses	O&M Expense	6,329,221		
6	General and Administrative	O&M Expense	12,564,408		
7	Total Operation and Maintenance Expense		36,161,355	3,469,362	39,630,717
8	Depreciation Expense	Depreciation Expense	15,462,814	2,736,430	18,199,244
9					
10	Taxes Other Than Income	Taxes Other Than Income	6,944,046	807,804	7,751,850
11					
12	Regulatory Amortization	Regulatory Amortizations	1,077,834	656,339	1,734,173
13					
14	Income Taxes - Permanent and Flow-through benefits	Income Taxes	(1,403,957)	(404,922)	(1,808,879)
15	Amortization of Deferred ITC, Excess Deferred Income Taxes (Including 2017 Tax Reform) and Deferred Tax Study Regulatory Liability	Tax Amortizations	(2,995,313)	1,458,831	(1,536,482)
16	Revenue Credits	Revenue Credits	(1,887,851)	(226,292)	(2,114,144)
17					
18	Total Net Expenses		$ 53,358,928	$ 8,497,552	$ **61,856,480**

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 11(D) of the Commission's Rules of Practice and Procedure (65-407 C.M.R. 110) within **20** days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought. Any petition not granted within **20** days from the date of filing is denied.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21** days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.

STANDARD & POOR'S
RATINGS SERVICES
McGRAW HILL FINANCIAL

RatingsDirect®

U.S. Regulated Electric Utilities' Annual Capital Spending Is Poised To Eclipse $100 Billion

Primary Credit Analyst:
Gabe Grosberg, New York (1) 212-438-6043; gabe.grosberg@standardandpoors.com

Research Contributor:
Nitin Saxena, New York (212) 438-7257; nitin.saxena@standardandpoors.com

Table Of Contents

U.S. Regulated Electric Utilities' Annual Capital Spending Is Poised To Eclipse $100 Billion

In recent years, U.S. electric utilities have intensified their capital spending, in part, to update and replace aging infrastructure. They've also had to boost spending to pay for smart grid technology, increased security to safeguard against physical and cyber attacks, and system hardening to protect against more volatile weather. Moreover, the industry is now exploring ways to meet the required carbon pollution reductions under the EPA's recently proposed Clean Power Plan, which seeks to reduce carbon dioxide emissions. Under this plan, utilities would likely generate less electricity from coal and more electricity from other less carbon-intensive sources, which would require significant incremental capital investments.

Standard & Poor's Ratings Services believes this ever-growing need to fund improvement projects and comply with upcoming regulations could pressure utilities' financial measures, resulting in almost consistent negative discretionary cash flow throughout this higher construction period. However, we expect that utilities will be able to maintain their largely investment-grade credit quality by effectively managing regulatory risk and possibly seeking new creative ways to finance the necessary higher spending levels. (Watch the related CreditMatters TV segment titled, "Why U.S. Regulated Electric Utilities' Annual Capital Spending Continues To Soar," dated Aug. 4, 2014.)

Overview

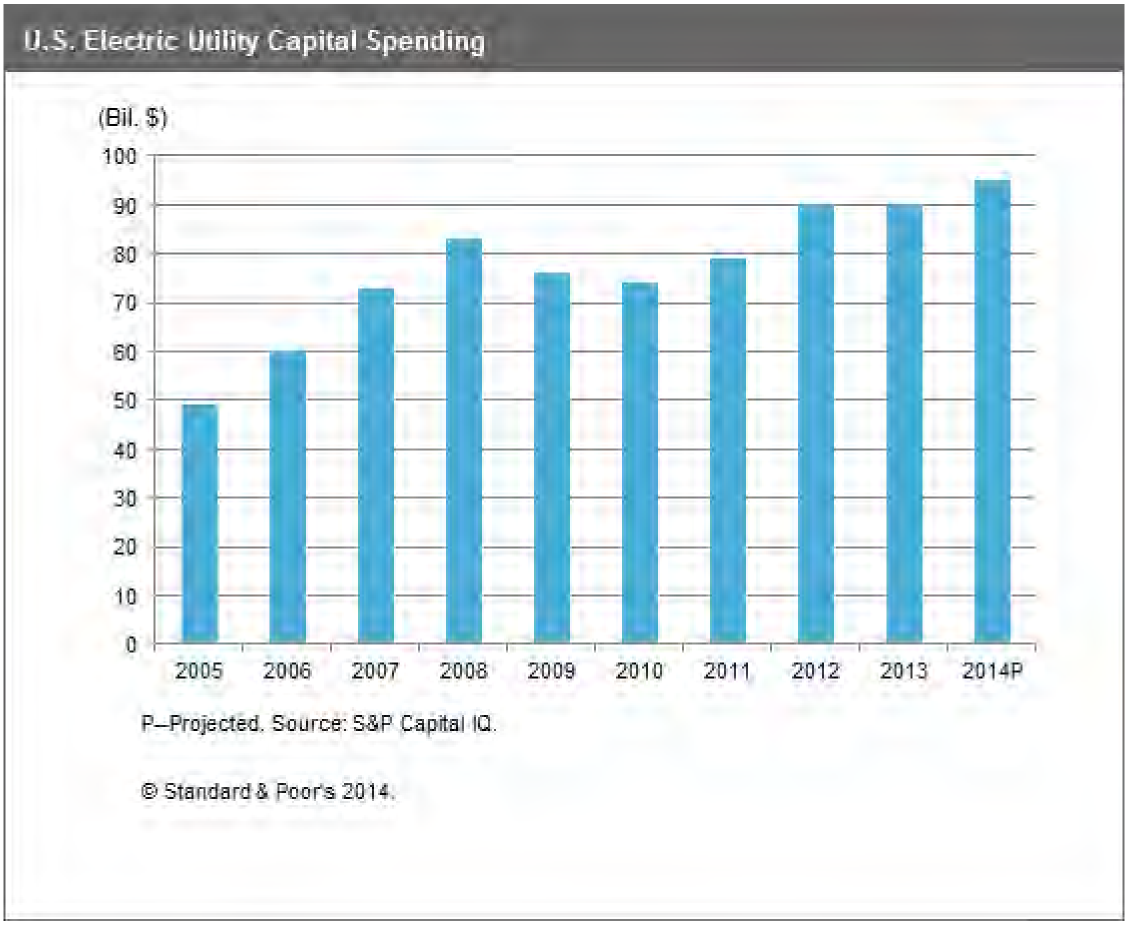
- Annual capital spending will continue to increase, likely reaching more than $100 billion by 2017.
- Capital spending to update and replace old or outdated infrastructure has been on the rise for the past decade.
- When the EPA finalizes its proposed guidelines, utilities will be mandated to further reduce carbon emissions.
- Total incremental capital spending to reduce carbon pollution will reach about $90 billion to $120 billion.
- Managing regulatory risk and financing upcoming compliance projects will remain key to sustaining credit quality.

Capital Spending Rides A Rising Tide

Over the past 10 years, capital spending in the U.S. electric utility industry has nearly doubled, growing at an annual compounded rate of about 8%. Year-over-year capital spending almost uniformly increased with the exception of the post-Great Recession years of 2009 and 2010. Before the recession (2005-2008), utilities mostly focused incremental capital spending on increasing generation capacity to meet higher load growth projections. Between 2011 and 2014, utilities were primarily concerned with replacing aging infrastructure, complying with environmental regulations, building new transmission lines, and developing renewable energy.

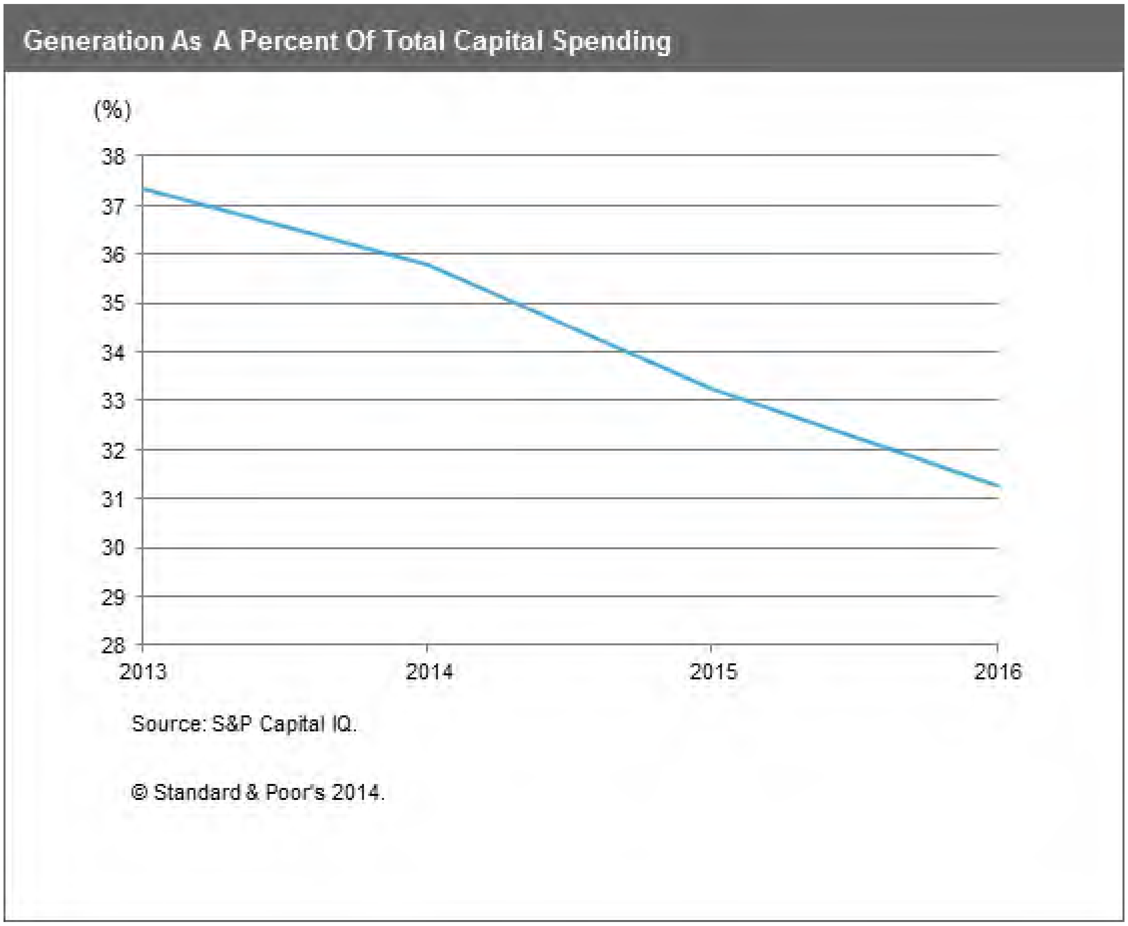
We project that capital spending will reach an all-time high of about $95 billion in 2014, reflecting growing funding needs for environmental projects and new transmission lines (see chart 1). For 2015-2016, we expect capital spending to moderate, with higher transmission spending partly offsetting a decrease in spending for environmental-related generation projects. The decline in environmental-related capital spending reflects the completion of many of the necessary projects for much of the coal-fired generation to meet the U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS).

Chart 1



We expect transmission spending to continue to rise. FirstEnergy Corp., Ameren Corp., ITC Holdings Corp., Xcel Energy Inc., American Electric Power Co. Inc., and Northeast Utilities are among the companies that are increasingly adding transmission for reliability, new base-load generation, or to incorporate renewable energy. We believe this trend will accelerate as the renewable energy sector continues to grow. Based on our forecast for reduced environmental-related generation spending and higher transmission spending, we expect the relative percentage of generation spending compared with the industry's total capital spending to decline over the next two years (see chart 2). However, beginning in 2017, we expect the industry's generation and overall capital spending will pick up significantly, consistently exceeding $100 billion annually. This hike reflects some utilities' decisions to proactively boost lower carbon-intensive generation capital spending to meet the EPA's recently announced proposed carbon pollution rules.

Chart 2

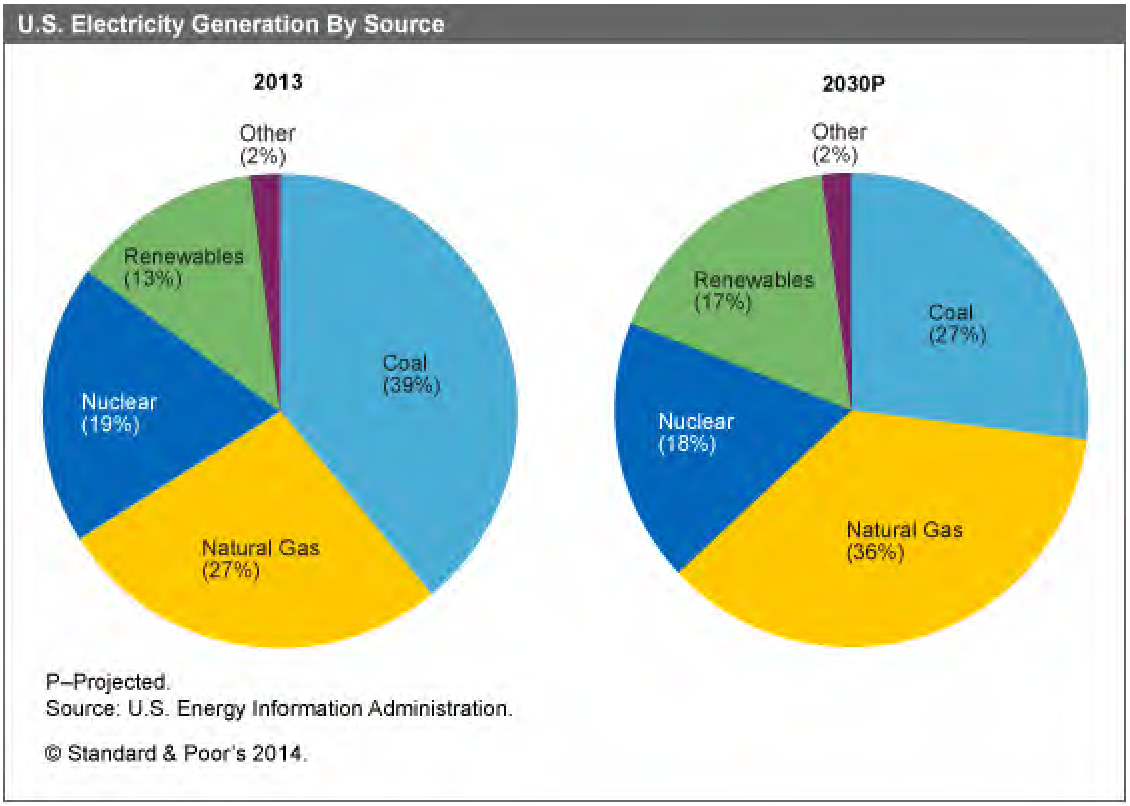


Coal-Fired Electricity Generation Will Continue To Decline

In June 2014, the EPA proposed the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. The EPA's goal is to reduce carbon dioxide emissions by 30% by 2030 compared with 2005 levels but at the same time allow states some flexibility for implementation. We understand that the EPA expects to issue its final rules by June 2015 and states will have approximately one year to submit plans outlining how they intend to reach their goals. In addition, under certain circumstances, states can request an extension, allowing them to submit their plans as late as June 2018.

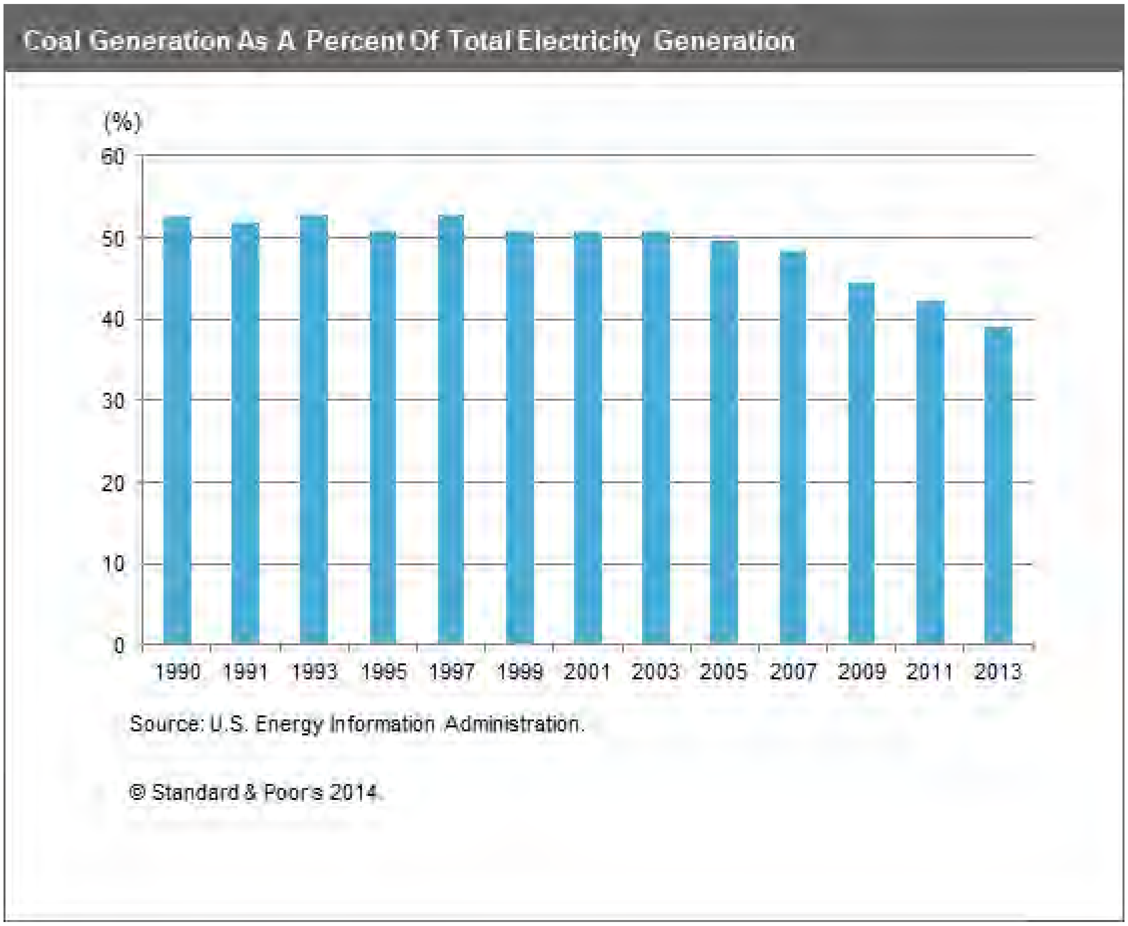
Based on our analysis of the current proposed rule, we expect total annual coal-fired generation to gradually decrease by 2030 to about 1,200 terawatt hours (tWh) from about 1,600 tWh in 2013. In other words, we expect coal to eventually account for just 27% of the U.S.'s annual total electric generation output compared with about 39% in 2013 (see chart 3). Of course, if the EPA's final rules are materially different from the proposed rules, we would adjust our analysis accordingly.

Chart 3



The reduction in coal generation isn't new for the electric utility industry and follows a longer-term trend. In 2007, coal fired-generation represented about 50% of total electric generation (see chart 4). The decline to 39%, in 2013, reflects both lower priced natural gas and compliance with the EPA's environmental rules designed to improve air quality.

Chart 4



Carbon Reduction Will Require More Capital

Our analysis assumes that, overall, utilities will replace some base-load coal-fired generation with base-load gas-fired generation and intermittent renewable generation. While replacing coal with natural gas reduces carbon dioxide emission, it doesn't eliminate it entirely. On average, coal generation emits about 210 pounds of carbon dioxide per million Btu and natural gas emits approximately 116 pounds of carbon dioxide per million Btu. We expect the EPA's carbon pollution rules will, in total, increase the industry's capital spending by about $90 billion to $120 billion. We expect most of the incremental capital spending will be incurred as utilities build the infrastructure to generate electricity from sources other than coal, primarily natural gas. We base our analysis on an average new build cost of combined cycle natural gas generating facility of about $1,200 per kilowatt, with a capacity factor of about 70%. We expect some of the more proactive companies to begin their initial carbon pollution capital spending in 2017, pushing the industry's annual capital spending to consistently greater than $100 billion.

Capital Spending May Strain Financial Measures, But Ratings Will Remain Largely Stable

Currently, the vast majority of the regulated utility industry's credit ratings are in the investment-grade category, with almost 95% falling within the 'BBB' and 'A' ranges. In addition, about 85% of the industry has a stable outlook, reflecting our longer-term view that the industry will be able to manage its ongoing risks. This is largely due to the essential service that these companies provide, the rate-regulated nature of the business that generally allows them to recover their costs from customers, the industry's refocus on rate-regulated businesses, and the businesses' overall effective management of regulatory risk.

However, there is little doubt that the U.S. electric industry needs to make record capital expenditures to comply with the proposed carbon pollution rules over the next several years, while maintaining safety standards and grid stability. We believe the higher capital spending and subsequent rise in debt levels could strain these companies' financial measures, resulting in an almost consistent negative discretionary cash flow throughout this higher construction period. To meet the higher capital spending requirements, companies will require ongoing and steady access to the capital markets, necessitating that the industry maintains its high credit quality. We expect that utilities will continue to effectively manage their regulatory risk by using various creative means to recover their costs and to finance their necessary higher spending. Cost recovery will most likely include some combination of more frequently filed rate cases, formula rates, securitization, special rate riders, and regulatory preapproval of projects (see "U.S. Utilities' Capital Spending Is Rising, And Cost Recovery Is Vital," published May 14, 2012, and "U.S. Electric Utilities Look To Curb Emissions While Maintaining Credit Quality," published May 11, 2011 on RatingsDirect).

S&P Global
Ratings

RatingsDirect®

Assessing U.S. Investor-Owned Utility Regulatory Environments

Primary Credit Analyst:
Todd A Shipman, CFA, Boston (1) 617-530-8241; todd.shipman@spglobal.com

Table Of Contents

Assessing U.S. Investor-Owned Utility Regulatory Environments

Regulatory advantage is the most heavily weighted factor when S&P Global Ratings analyzes a regulated utility's business risk profile. One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions where a utility operates. A utility management team's skill in dealing with regulatory risk can sometimes overcome a difficult regulatory environment. Conversely, companies' regulatory risk can increase even with supportive regulatory regimes if management fails to devote the necessary time and resources to the important task of managing regulatory risk. We modify our assessment of regulatory advantage to account for this dynamic in our ratings methodology (for the criteria we use to rate utilities, see "Corporate Methodology," and "Key Credit Factors For The Regulated Utilities Industry," published Nov. 19, 2013, on RatingsDirect.)

There are specific factors we use in the U.S. to assess the credit implications of the numerous regulatory jurisdictions here that help us determine the "preliminary regulatory advantage" in our credit analysis of each investor-owned regulated utility. We organize the subfactors of regulatory advantage into four categories:

- Regulatory stability,
- Tariff-setting procedures and design,
- Financial stability, and
- Regulatory independence and insulation.

Regulatory Stability

The foundation of our opinion of a jurisdiction is the stability of its approach to regulating utilities, encompassing transparency, predictability, and consistency. Given the maturity of the U.S. investor-owned utility industry, the long history of utility regulation (going back to the early 20th century) and the well-established constitutional protections accorded to utility investments, we emphasize the principle of consistency when weighing regulatory stability. We also incorporate the degree to which the regulatory framework either explicitly or implicitly considers credit quality in its design.

Regulatory Change Can Bring Stability, Or Take It Away

While stability is one of the four pillars of our approach to evaluating regulatory risk, experience shows us that it's not an absolute positive or negative for creditors. Change can boost or lessen risk, and any improvement in a regulatory regime will overcome any negative connotations of instability. A good example is Michigan, which in about 2008 revamped its whole approach to utility regulation. As implemented in subsequent years by the Michigan Public Service Commission, the reforms have almost completely transformed the regulatory environment in that state.

However, during any period of change, we see the uncertainties surrounding the process and the outcome as possible major causes of risk. A more recent and still ongoing example is New York, where the Public Service Commission's (NYPSC) Reforming the Energy Vision (REV) proceeding is possibly revving up risk for utilities. While the NYPSC seemed at first to be focusing more on high-minded policy questions than on making a lot of changes to day-to-day operations, the current phase could eventually disrupt the way utilities make money and affect their ability to earn the authorized return. If the end result is greater operating risk with no opportunity to earn greater returns, our assessment of the regulatory environment could change.

Durability of regulatory system

An established, dependable approach to regulating utilities is a hallmark of a credit-supportive jurisdiction. Creditors lend capital to utilities over long periods to fund the development of long-lived assets. A firm understanding of the basic "rules" that will govern how the utility will recover its costs, including servicing its debt and the return on its capital over an extended period, is essential to accurately assess credit risk. Major or frequent changes to the regulatory model invariably raise risk due to the possibility of future changes. Steady application of transparent, comprehensible policies and practices lowers risk.

How long a regulatory framework has been in place is the most important factor in this area. We view jurisdictions as most supportive when there have been no major changes or where the approach has been consistent for a long time and is not prone to further changes. Jurisdictions that have undergone a major, fundamental change in the regulatory paradigm that seems to be working well are a little less supportive, and less so a jurisdiction that is transitioning to a new regulatory approach. Credit risk rises if the transition attracts political attention. The less-supportive jurisdictions are those that frequently alter the basic regulatory approach. We also view the framework's development less favorably if policy disputes or legal actions cause contention, indicating that the political consensus regarding utility regulation is fragile.

Some jurisdictions permit competitive markets to prevail for some important functions of the delivery of utility services, notably wholesale markets for electricity and retail markets for electric or gas service. In others, vertical integration is the norm. A jurisdiction's credit-supportiveness is more prone to suffer if market forces directly influence major cost items that utilities could otherwise control through cost-based regulation because of the potential volatility it creates. The risk inherent in a market-based model is straightforward: utility rates are more volatile when markets influence them rather than fully embedded costs, and regulators are apt to resist full and timely recovery when market price changes are abrupt and substantial (and perhaps misunderstood). We observe less support for credit quality in jurisdictions that are in the midst of deregulating important parts of the utility framework. The uncertainty of the timing of reaching the outcome--and what the result will be--is a negative factor from a credit perspective. Utilities are also prone to financial stress when the transition to competition causes potential "rate shock" for customers that regulators could resist.

Transparency of regulatory framework and attitude toward credit quality

We believe regulation works best when it is rule-based. Creditor interests are better protected by the presence of and adherence to a pre-set code of rules and procedures that we can look to when assessing risk. Risk is lower when the rules are more transparent and when they take into account a utility's financial integrity. We regard jurisdictions that require regulators to protect utilities' financial soundness and have transparent policies and procedures as the most credit-supportive. We ascribe higher risk in jurisdictions where policies and procedures support financial integrity, but where inconsistency can selectively arise. We believe a jurisdiction provides even less support when transparency merely exists. We see less support when any of these credit factors are absent, or if the regulator's record on following precedent is poor.

Tariff-Setting Procedures

We review rate decisions as part of our surveillance on each U.S. utility. We focus on the jurisdiction's overall approach to setting rates and the process it uses to establish base rates (practices pertaining to separate tariff provisions for large expenses are in the "Financial Stability" part of our analysis). We focus on whether base rates, over time, fairly reflect a utility's cost structure and allow a fair opportunity to earn a compensatory return that provides creditors with a financial cushion that supports credit quality. If the process is geared toward an incentive-based system, our analysis centers on the risks related to the incentive mechanisms. If the jurisdiction has vertically integrated utilities, we review the resource procurement process and assess how it affects regulatory risk.

Rate Cases Can Affect Creditworthiness

Although not common, rate case outcomes can sometimes lead directly to a change in our opinion of creditworthiness. Often it's a case that takes on greater importance because of the issues being litigated. For example, in 2010, we downgraded Florida Power & Light and its affiliates following a Florida Public Service Commission rate ruling that attracted attention due to drastic changes to settled practices on rate case particulars like depreciation rates. More recently, in June 2016, we downgraded Central Hudson Electric & Gas due to our revised opinion of regulatory risk. While that reflected the company's own management of regulatory risk, it was prompted in part by other rate case decisions in New York that highlighted the overall risk in the state.

Sometimes change comes from outside the usual rate case process. The aforementioned improvement in Michigan (see the previous sidebar) came from legislative changes that reformed rate case procedures such as interim rate increases and time limits on rate decisions. In March 2016, we affirmed our ratings on Entergy Corp. and kept the outlook positive based on the prospect of lower regulatory risk as the company pursues strategic changes in its various jurisdictions. For instance, legislation in Arkansas allowing for formula rates could better enable Entergy to manage regulatory lag and earn its authorized return.

Ability to timely recover costs

We review authorized returns and capital structures in our analysis, but we focus mainly on actual earned returns. Examples abound of utilities with healthy authorized returns that have no meaningful expectation of earning those returns due to, for example, rate case lag (i.e., the relationship between approved rates and the age of the costs used to set those rates) or expense disallowances. Also, the stability of the returns is as important as the absolute level of financial returns, and we note the equity component in the capital structure used to generate the revenue requirement in rate proceedings. Higher authorized and earned returns and thicker equity ratios translate into better credit measures and a more comfortable equity cushion for creditors. We consider a regulatory approach that allows utilities the opportunity to consistently earn a reasonable return as a positive credit factor.

A very credit-supportive jurisdiction is one in which all of the utilities it regulates consistently earn above-average returns. We assess jurisdictions lower if only some of them do, and lower still if the earnings records are below average or highly variable from year to year. We deem jurisdictions as weaker when all utilities earn well-below-average returns, and we consider jurisdictions where all utilities consistently earn exceedingly poor returns, including years with negative returns, as weakest.

We consider "regulatory lag" along with the record of earned returns to assess timeliness. Credit-supportive jurisdiction typically have a track record of little regulatory lag, indicating that responsibility for a poor or uneven earnings history lies more with management than its regulators. In addition to the regulator's efficiency in completing rate cases, we consider the obsolescence of the costs on which the rates are based, the timing of interim rates, and other practices (such as allowing rates to automatically change in a future period based on inflation) that affect a utility's ability to earn its authorized return.

If a jurisdiction uses incentives as the primary ratemaking tool and institutes a comprehensive incentive program that allows revenues and costs to diverge, we evaluate the incentive mechanisms' effect on a utility's earnings capability and stability. A common approach features an extended period between base rate reviews, during which rates change according to a formula based on inflation, a predetermined productivity factor, and capital spending. An incentive-based program can be close to credit-neutral compared with systems that permit more frequent and dynamic rate changes if the risk is symmetrical (i.e., an equal opportunity to earn over or under the authorized return and equivalent reward or penalty for doing so) and limited (a maximum or minimum earnings band). The effect on regulatory risk depends on whether we believe the efficiency targets are realistic and achievable, the regulator's treatment of disparities in actual versus authorized spending, and the framework's flexibility to adjust returns for capital market conditions. If there are operating standards, we determine whether they fairly reward or punish utilities if performance deviates from expectations.

There is a muted effect on regulatory risk in jurisdictions where incentives are not central, but are instead used only to augment cost-of-service regulation. A moderate amount of incentives that carry symmetrical risks can even modestly support better credit quality. For example, a fuel-adjustment and purchased-power clause with a sharing mechanism that affects less than 10% of the total fuel costs and cuts both ways when commodity markets change can modestly reduce risk by offering the utility a mild incentive for effective procurement and efficient operations, without unduly exposing it to commodity price risk.

We typically view jurisdictions as credit-supportive if regulators use symmetrical incentive mechanisms sparingly in the rate-setting process. When incentives play a larger role in the rate-setting approach, but are well-designed to evenly allocate risk, we see less support for credit quality. We regard still lower jurisdictions where incentives dominate and are poorly designed. Jurisdictions where incentives significantly degrade risk and are part of a comprehensive incentive regime harbor the most risk for creditors.

Financial Stability

When we evaluate U.S utility regulatory environments, we consider financial stability to be of substantial importance. Cash takes precedence in credit analysis. A regulatory jurisdiction that recognizes the significance of cash flow in its decision-making is one that will appeal to creditors.

Creative Ratemaking Can Help…If Used Correctly

The ability of financial stability factors to help a utility maintain and smooth its cash flow gives prominence to this area of our analysis. In addition to the near-ubiquitous fuel clauses, we see utilities give more attention to obtaining so-called "disc" mechanisms (DSIC, for distribution system investment charge, is a common acronym for this kind of rate adjustment) that accelerate and stabilize cash flow realization when a utility pursues a strategy of boosting rate base to fuel earnings growth.

For instance, Duquesne Light recently filed for a DSIC mechanism in Pennsylvania in conjunction with a long-term plan to improve its distribution system. Approval, requested for October, would enhance our view of Duquesne's ability to manage regulatory risk, because it would consequently be joining the other Pennsylvania utilities that already benefit from this mechanism. On the other end of the spectrum, Mississippi Power's ongoing travails in obtaining rate relief for its Kemper coal-fired plant, which has experienced significant cost and schedule problems, points to how regulatory risk can deteriorate under stress when well-established procedures for handling large and risky capital projects are absent or not followed.

Treatment of significant expenses

When utilities have major expenses such as fuel and purchased power/gas/water, the presence of separate tariff provisions to facilitate full and contemporaneous recovery is the most prominent factor in this part of our analysis. The timely adjustment of rates in response to changing commodity prices and other expenses that are largely out of management's control is a key feature of a credit-supportive regulatory jurisdiction. The analysis centers on the special tariff mechanisms to determine their effectiveness in producing the cash flow stability they are designed to achieve. The frequency of rate adjustments, the ability to quickly react to unusual market volatility, and the control of opportunities to engage in hindsight disallowances of costs could affect our analysis almost as much as whether the tariff provisions exist at all. The record of disallowances plays a part when we assess regulatory advantage.

We consider jurisdictions to be very credit-supportive if utilities can recover all high-expense items through an automatic tariff clause that is based on projected costs, adjusts frequently, and has no record of any significant disallowances. We see more risk if separate mechanisms exist, but lack some of the above features. We view jurisdictions that lack independent rate mechanisms for large expenses and have a record of significant disallowances as weakest.

Treatment of capital spending

When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.

Very supportive jurisdictions offer a separate recovery mechanism for all capital spending, a mandated current cash return during construction, and a bonus return for some or all capital projects. We deem a jurisdiction weaker if there is a separate mechanism for only certain kinds of spending and the cash return and higher return are subject to the regulator's discretion. We view jurisdictions that don't allow separate recovery or a current return as being lower on the scale. We assess a jurisdiction as weaker still when it doesn't have independent rate mechanisms for capital projects, and we view it as most risky when full recovery occurs only after a utility's assets become operational.

Cash-smoothing mechanisms

We have a more positive view of jurisdictions that use innovative regulatory provisions that help to smooth cash flow from period to period. For a jurisdiction that focuses on incentives in its basic approach to ratemaking, through multiyear rate plans or a formula rate plan, we view the availability of "reopeners" (to adjust rates for unexpected events out of the utility's control) as key to this part of our analysis. The utility's ability to petition for a rate increase when unexpected or uncontrollable costs arise in the midst of a long-term rate plan is a critical risk mitigant.

Other examples of risk-dampening regulatory policies include hedging program approvals, and decoupling (the separation of a utility's profits from sales) or weather-related mechanisms. If a utility seeks approval of a hedging program to manage exposure to commodity prices, it can reduce risk if there's a clearly stated hedging policy that its regulator has endorsed, and a track record of activity that conforms to the policy that has not been subject to regulatory second-guessing. A well-designed decoupling or weather-normalization mechanism that efficiently adjusts rates to offset the sales effect of economic conditions, customer usage trends, or weather will soften earnings and cash flow volatility to the benefit of creditors. If applicable, we view a record of regulatory responsiveness to extreme events for utilities that are prone to violent or disruptive weather (like hurricanes) as favorable for credit quality.

A jurisdiction is more credit-supportive if it makes extensive use of extraordinary and credit-supportive rate mechanisms. Also favorable are jurisdictions that use innovative mechanisms selectively, or have regulators that are receptive to reopeners where incentives are the main ratemaking method.

Regulatory Independence And Insulation

The role of politics in U.S. utility regulation is often misunderstood. In most jurisdictions, the regulator's function is to set and regulate rates and service standards with due regard not only for the interests of those who advance the capital needed to provide safe and reliable utility service, but for other constituents as well. Creditors should recognize that utility regulation harbors political as well as economic risks. Therefore, how politics could influence regulation helps us evaluate a regulatory environment.

Political Influence On Utility Regulation Can Yield Unexpected Results

This is often the most variable area of our analysis and the most difficult to assess. The most dramatic, fairly recent reminder of how political forces can influence regulatory risk was last year's unexpected reversal by the popularly elected Mississippi Supreme Court of a significant rate increase granted for Mississippi Power to help pay for a major power plant under construction. Regulators, who were ordered to roll back rates and issue refunds, struggled to make decisions amid the strained political atmosphere and extra scrutiny that the Court's action had created. The episode also highlighted the greater regulatory risk that attends jurisdictions that expose regulators (and in this case the appellate court) to direct political accountability.

Another more recent example of political influence on regulation underscores the complexity of this area of analysis, because it featured many participants at both the federal and state level. Electric utilities in Ohio had a credible strategy for dealing with rising competitive risks in their merchant generation portfolios by offering the output to retail customers at pre-set prices on a long-term basis, which the state regulator approved. The federal regulator (Federal Energy Regulatory Commission, or FERC), responding to complaints by other generators that the plan would inhibit the operation of the competitive electricity market, essentially overruled the Ohio regulators and blocked the utilities from pursing the strategy that would have reduced its risk profile. It essentially decided that its political interest in and ideological commitment to efficient electricity markets overrode the state's political interest in stable electric rates. The saga is still continuing with attempts to bypass the FERC's ruling through other means, but no matter what the ultimate result, we see how political considerations can increase risk.

Political independence of regulator

The primary factor in this part of our analysis is the regulators' (and, when relevant, the judicial body that reviews the regulators' decisions) political independence. We think it's more credit-supportive when the regulator is substantially independent of the political process. Jurisdictions are somewhat less favorable when insulation is strong, such as when the executive branch of government appoints regulators subject to legislative approval. We consider jurisdictions to be further down the scale when the same voters who pay utility bills directly elect the regulators, but institutional efforts have been made to erect some shield for regulators from transient political concerns. We view jurisdictions that arrange for direct political accountability of regulators that persistently influences regulatory decisions as less supportive.

Record of direct political intervention

The overall atmosphere that a regulator operates in can affect its ability to deliver sound, fair, and timely rate decisions and set prudent regulatory policies that assist utilities in managing business and financial risk. In this part of our evaluation, we may consider the tone that politicians set, the history of political insulation given to the regulatory body and the courts that review its actions, and the behavior of important constituencies that intervene in utility proceedings. We also track the public visibility of utility issues, because we believe that the likelihood of constructive regulatory behavior increases with the comparative obscurity of utility issues.

We view a jurisdiction as having a lower risk if the regulatory environment is marked by cooperative attitudes and constructive interventions in important matters before the regulator. We assess a jurisdiction lower when the atmosphere is more combative and restricts the regulator's ability to act in the long-term best interests of all parties. We consider jurisdictions as weaker if the regulatory environment is so infused with short-term political influence over regulatory decisions that the regulator can't effectively consider investor interests in its decisions.

Related Criteria And Research

Related Criteria

- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013

S&P Global
Ratings

RatingsDirect®

Summary:
American Water Works Co. Inc.

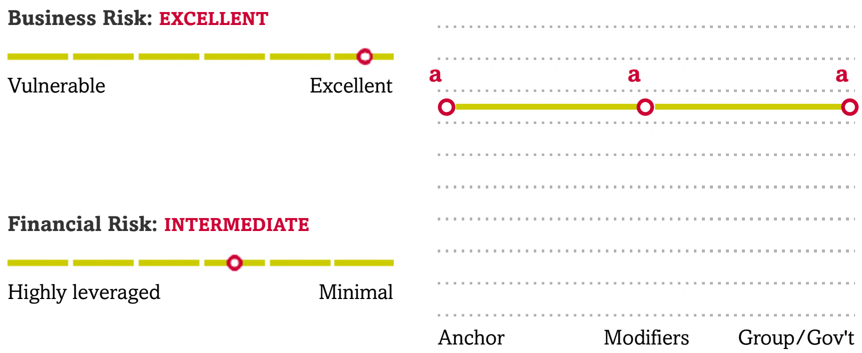
Primary Credit Analyst:
Gerrit W Jepsen, CFA, New York (1) 212-438-2529; gerrit.jepsen@spglobal.com

Secondary Contact:
Safina Ali, CFA, New York (1) 212-438-1877; safina.ali@spglobal.com

Table Of Contents

Summary:

American Water Works Co. Inc.



CORPORATE CREDIT RATING

A/Stable/A-1

Rationale

Business Risk: Excellent	Financial Risk: Intermediate
• A low-risk, rate-regulated water utility; • Geographic and regulatory diversity; and • Effective management of regulatory risk.	• Use of the low volatility table based on the company's low-risk, rate-regulated water utilities and effective management of regulatory risk; • Core financial measures that are consistent with the intermediate financial risk profile category; • Large capital spending program; and • Expectation of stable cash flows.

Outlook: Stable

The stable rating outlook on American Water Works Co. Inc. (AWK) reflects S&P Global Ratings' expectation that the company will continue to effectively manage its regulatory risk while maintaining financial measures that remain consistently within the intermediate financial risk profile category. Under our baseline forecast, we expect funds from operations (FFO) to debt of more than 17%-19%.

Downside scenario

We could lower the ratings on AWK if regulatory risk increased or performance stalled or deteriorated, which could result from substantial debt financing of capital spending or acquisitions, such that FFO to debt fell to less than 15%.

Upside scenario

We could raise the ratings if FFO to total debt consistently remained over 20%. This could take place if the company managed its regulatory risk and achieved higher than expected rate case outcomes, along with continuing to prudently manage expenses.

S&P Global Ratings' Base-Case Scenario

Assumptions

- Continued effective management of regulatory risk;
- Capital spending of about $1.2 billion;
- Dividends to grow roughly 5%;
- Negative discretionary cash primarily due to higher capital spending; and
- Refinancing of upcoming debt maturities.

Key Metrics

	2015A	2016E	2017E
FFO/total debt (%)	17.3	16-18	16-18
Total debt/EBITDA (x)	4.5	4.3-4.8	4.3-4.8

A--Actual. E--Estimated. FFO--Funds from operations.

Business Risk: Excellent

We view AWK's business risk as excellent, based on its monopolistic and lower-risk, rate-regulated water distribution business that provides an essential service in regulatory jurisdictions, which we generally view as supportive of credit quality. In addition, the company's geographic diversity, reliability, and efficiency further support its business risk profile. AWK's elevated capital spending requirements for infrastructure replacement, increased compliance costs to meet water quality standards, and reliance on acquisitions to provide growth partly offset these strengths. The company serves approximately 3.2 million water and wastewater customers across 16 states. Based on EBITDA, we consider AWK's operations about 95% regulated and 5% unregulated. Although we view the unregulated businesses as having higher business risk compared with the regulated operations, we also recognize AWK's unregulated businesses marginally affect the company's business risk profile because of its modest expected capital requirements, affiliation with its regulated service jurisdictions, and lower-risk service contracts.

AWK is regulated by the public utility commissions of the states in which they operate namely New Jersey, Pennsylvania, Illinois, Missouri, Indiana, California, and West Virginia, which represent approximately 87% of revenues and 85% of customers. The company benefits from constructive mechanisms such as the distribution system investment charge (DSIC) in a number of its jurisdictions, which allows for the recovery of high capital spending outside of a traditional rate-case proceeding and reduces regulatory lag.

Financial Risk: Intermediate

We assess AWK's financial risk profile as intermediate based on our low volatility benchmark ratios, reflecting the company's lower-risk, rate-regulated water business model and its above-average management of regulatory risk. Under our base-case scenario, we expect FFO to debt to be about 17%, which is consistent with the intermediate category. We also expect AWK will continue to have negative discretionary cash flow, reflecting its higher capital spending level. Fundamentally, we expect AWK will continue to fund its investments in a manner that preserves credit quality.

The combination of the excellent business and intermediate financial risk profiles leads to a choice of 'a+'/'a' anchor, we choose the 'a' anchor, which captures the relatively higher risk associated with the company's non-utility businesses as compared to regulated utility operations.

Liquidity: Adequate

Our short-term rating on AWK is 'A-1'. We assess AWK's liquidity as adequate because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even with a 10% EBITDA reduction. The adequate assessment also reflects the company's generally prudent risk management, sound relationships with banks, and a generally satisfactory standing in credit markets.

Principal Liquidity Sources	Principal Liquidity Uses
• Credit facility availability of at least $1.25 billion for the 12 months ending March 31, 2017; and • FFO of about $1.3 billion over for the 12 months ending March 31, 2017.	• Debt maturities of about $680 million, including outstanding short-term debt, for the 12 months ending March 31, 2017; • Capital spending of about $1.3 billion for the 12 months ending March 31, 2017; and • Dividends of roughly $275 million for the 12 months ending March 31, 2017.

Other Credit Considerations

Our assessment of modifiers results in no further changes to the anchor score.

Group Influence

Under our group rating methodology, we view AWK as the parent of a group whose members are American Water Capital Corp., New Jersey American Water Co, and Pennsylvania American Water Co. AWK's group credit profile is 'a', leading to an issuer credit rating of 'A'.

Ratings Score Snapshot

Corporate Credit Rating

A/Stable/A-1

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Intermediate

- **Cash flow/Leverage:** Intermediate

Anchor: a

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a

- **Group credit profile:** a

Recovery Analysis

Key Analytical Factors

We assign recovery ratings to first-mortgage bonds (FMBs) issued by U.S. utilities, which can result in issue ratings being notched above a corporate credit rating on a utility depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of "secured utility bond" (SUB) that qualify for a recovery rating as defined in our criteria (see "Collateral Coverage and Issue Notching Rules for '1+' and '1' Recovery Ratings on Senior Bonds Secured by Utility Real Property, Feb. 14, 2013). The recovery methodology is supported by the ample historical record of 100% recovery for secured bondholders in utility bankruptcies in the U.S. and our view that the factors that enhanced those recoveries (limited size of the creditor class and the durable value of utility rate-based assets during and after a reorganization given the essential service provided and the high replacement cost) will persist in the future.

Under our SUB criteria, we calculate a ratio of our estimate of the value of the collateral pledged to bondholders relative to the amount of FMBs outstanding. FMB ratings can exceed a corporate credit rating on a utility by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories, depending on the calculated ratio.

New Jersey American Water and Pennsylvania American Water's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating one notch above the corporate credit rating.

American Water Capital Corp.'s senior unsecured debt is rated the same as the company's issuer credit rating because priority obligations are less than 20% of the total assets of American Water Works.

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Methodology, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 07, 2013
- Collateral Coverage And Issue Notching Rules For ‘1+’ And ‘1’ Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008

- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	**Intermediate**	Significant	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	**a+/a**	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-