COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	**CASE NO. 2020-00349**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	**CASE NO. 2020-00350**

REBUTTAL TESTIMONY OF
DANIEL K. ARBOUGH
TREASURER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: April 12, 2021

TABLE OF CONTENTS

I. BACKGROUND

Q. Please state your name, position and business address.

A. My name is Daniel K. Arbough. I am the Treasurer for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies"), and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut certain arguments made in the direct testimony of intervenors in this case. Specifically, I will explain that (1) securitization financing is not an appropriate solution to the need to retire certain coal-fired generating units and the Attorney General's ("AG") and Kentucky Industrial Utility Customers, Inc.'s ("KIUC") witness Mr. Kollen's and Kroger witness Mr. Bieber's proposals should be rejected; (2) the AG/KIUC witness Mr. Baudino's adjustment to the long-term debt interest rate is unreasonable; (3) the AG/KIUC witness Mr. Kollen's proposed disallowance for inspection costs is unwarranted; and (4) the AG/KIUC witness Mr. Kollen's adjustments to pension and OPEB expenses are unreasonable. In addition, I will provide an update to the projected pension and OPEB expenses used in the filing.

II. SECURITIZATION FINANCING

Q. Please explain Mr. Kollen's recommendation regarding securitization.

A. In his testimony, Mr. Kollen proposes the use of securitization financing for *all* of the Companies' coal-fired and gas-fired units once retired. This proposal sharply contrasts with the Companies' proposal to update depreciation rates for certain generating units. Securitization, as noted in Mr. Kollen's testimony, is a form of asset-based financing that involves the use of government-approved bonds as a substitute for the debt and equity mix that is typically used to finance investor-owned utility capital requirements. Because of the government's involvement with the process, securitization is only available as a form of financing in states that have enacted enabling legislation. In Kentucky, no securitization legislation has been introduced or enacted. As such, it is unavailable as a form of financing and cannot be employed in this proceeding.

Q. Does Kroger witness Mr. Bieber also advocate for the use of securitization financing?

A. Yes, but not as thoroughly as Mr. Kollen. Mr. Bieber describes securitized bonds as a "potential tool that the Commonwealth of Kentucky might consider" but concedes that the "securitization of undepreciated plant would need statutory authorization."[1]

Q. Do you oppose the use of securitization financing for Mill Creek Units 1 and 2 and Brown Unit 3?

A. Yes. Securitization financing is not appropriate to address the potential undepreciated plant balances for Mill Creek Units 1 and 2 and Brown Unit 3. As a fundamental matter, the Companies are entitled to an opportunity to earn a return on prudently incurred investments. There is no question that the Companies' Mill Creek Units 1 and 2 and Brown Unit 3 are prudently incurred investments that have served the needs of customers for decades and will continue to do so for years.

Q. Do you agree with Mr. Kollen's calculations of savings associated with securitization financing?

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[1] Direct Testimony of Justin Bieber on behalf of The Kroger Co. ("Bieber Direct") dated March 5, 2021 at 10.

A. No. Mr. Kollen's calculations are highly speculative and presuppose events that have not occurred and may never occur.

Q. Please describe why Mr. Kollen's calculations are speculative.

A. Mr. Kollen's calculations are highly speculative for two reasons. First, as Mr. Kollen recognizes, the proposal is conditioned on legislative action, which has not occurred. The financial practicality of securitization or the savings from it, if any, cannot be quantified in the abstract, and certainly not prior to knowing the terms of the necessary legislation. Even if the required legislation passes and securitization becomes a real possibility at some time in the future, it also would require a separate and distinct regulatory process to approve and implement the securitization transaction. Because none of the required conditions have been met or even proposed, it is entirely premature and inappropriate to contemplate—much less to make—financial decisions guided by hypothetical securitization. The South Carolina Public Service Commission recently rejected securitization proposals, noting that no legislation existed, and securitization proposals were entirely hypothetical.[2]

Second, Mr. Kollen attempts to justify the use of securitization by basing his analysis on the assumption of all coal-fired and gas-fired generating units being retired at the end of 2035. He indicates that he chose the end of the 2035 as the estimated retirement date to "correspond to the earliest date cited in President Biden's recent Executive Order directing various federal agencies and task forces to develop a

[2] *Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Inc. for Review and Approval of a Proposed Business Combination between SCANA Corporation and Dominion Energy, Inc. as May Be Required, and for a Prudency Determination Regarding the Abandonment of the V.C. Summer Units 2 & 3 Project and Associated Customer Benefits and Cost Recovery Plans*, Docket No. 2017-370-E, Order No. 2019-122 (S.C. PSC Feb. 12, 2019).

'comprehensive plan' that 'shall aim to use, as appropriate and consistent with all applicable law, all available procurement authorities to achieve or facilitate: (i) a carbon pollution-free electricity sector no later than 2035.'"[3] Assuming all coal-fired and gas-fired generation will need to be retired by 2035 based on this language is pure speculation. The same Executive Order states its objective as to "put the United States on a path to achieve net-zero emissions, economy-wide, by no later than *2050*."[4] The Companies are under no legal requirement to retire generation at this time. The use of securitization for such a speculative scenario is simply not ripe for decision and not a part of this proceeding.

Q. Are there credit risks associated with securitization?

A. Yes. The Moody's and Fitch articles included as Exhibit LK-31 to Mr. Kollen's testimony both recognize credit risks associated with securitization financing. Particularly, Fitch explains: "It is unfavorable from a credit viewpoint if the special tariff represents a significant portion of the total delivered cost of utility services, especially if it may affect the economic competitiveness of major industrial customers in the utility's service area."[5] Fitch also recognizes that special tariffs in excess of 20% of the customer bill are inconsistent with a "AAAsf" rating.[6]

Q. Do you agree with Mr. Kollen's statement on lines 21-24 on page 30 of his testimony that credit agencies tend to ignore securitization financing when issuing credit ratings?

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[3] Direct Testimony and Exhibits of Lane Kollen on behalf of the Kentucky Office of the Attorney General and Kentucky Industrial Utility Customers, Inc. ("Kollen Direct") dated March 2021 at 18.
[4] *Id.* at 18-19 (emphasis added).
[5] Exhibit LK-31, FitchRatings Article at 7-8.
[6] *Id.* at 8.

A. No, I do not. In the Moody's article included as part of Exhibit LK-31 of Mr. Kollen's testimony, Moody's disagrees with this assertion and explains: "We typically view securitization debt of utilities as on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers."[7] And as I previously mentioned, the Moody's and Fitch articles included as Exhibit LK-31 both recognize credit risks associated with securitization financing.

Q. Are there any other negatives in the securitization process that Mr. Kollen failed to mention?

A. Yes, there are a number of potential negatives. First, the debt would appear on the balance sheet of the Companies and would remain in place for many years, without corresponding equity to balance the capital structure. Thus, it would burden the Companies with high balance sheet debt leverage for decades. All operating risks faced by the Companies would be forced upon a much small equity allocation in the capital structure. Second, securitization is an extremely inflexible financial structure due to its long tenor, large size, and highly structured terms. For example, securitization financing requires a non-bypassable charge for each customer that must be trued-up at least annually. If sales volumes are lower than anticipated due to mild weather, energy conservation measures or departures of customers, a formula is used to adjust the amount of the securitization charge to recover the shortfall of projected revenues. As such, it would eliminate any future options for policy makers, the Commission, and the Companies' customers.

[7] Exhibit LK-31, Moody's Article at 2.

Q. Please describe why securitization is inappropriate for costs associated with the retirement of Brown Unit 3 and Mill Creek Units 1 and 2.

A. Mr. Kollen explains that securitization is a mechanism for "recovering the remaining net book and decommissioning costs of *prematurely retired* coal plants."[8] In the Moody's article included as Exhibit LK-31 to Mr. Kollen's testimony, Moody's recognizes that securitization is a "tool to recover, often significant, costs related to large or unforeseen developments[.]"[9] The retirements of Brown Unit 3 and Mill Creek Units 1 and 2 are not premature or unforeseen. The units' current retirement dates are no longer reasonable due to changes in economics and environmental regulations, and the proposed retirement dates in no way represent shorter lengths of life than usual for these three plants or some kind of extraordinary retirement.

Brown Unit 3 went into service in 1971; Mill Creek Units 1 and 2 went into service in 1972 and 1974, respectively. These units are not being prematurely retired; in fact, the units' age is well above the average age of retirement for U.S. coal-fired power plants.[10] Thus, the retirement of Brown Unit 3 and Mill Creek Units 1 and 2 are not the type of extraordinary events that necessitate the use of securitization financing.

Further, securitization financing carries fixed administrative costs. The Companies estimate such financing would cost each Company approximately $250,000 per year. In addition, there would be significant legal fees associated with drafting the appropriate legislation, producing the financing documents, and creating the special purpose entities required. Although these costs are significant (and unaccounted for) in

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[8] Kollen Direct at 31 (emphasis added).
[9] Exhibit LK-31, Moody's Article at 1.
[10] *More U.S. coal-fired power plants are decommissioning as retirements continue*, U.S. Energy Information and Administration, July 26, 2019, available at https://www.eia.gov/todayinenergy/detail.php?id=40212.

Mr. Kollen's proposal to use securitization financing for the retirement of all coal-fired and gas-fired generating units, they are even more significant when considering the financing for only three of the Companies' generating units.

Q. Are you aware of any precedent in which securitization took place over the objections of a utility?

A. No. To my knowledge, in all precedent transactions, the utility company was a willing and cooperative sponsor of the securitization transaction. This is not the case here and is one of the many reasons why securitization financing is inappropriate and should be rejected.

III. LONG-TERM DEBT

Q. Please summarize Mr. Baudino's adjustment to the Companies' long-term debt interest rate.

A. The Companies have forecast long-term debt issuances that are projected to occur by June 30, 2021. KU is expected to have a long-term debt issuance of $200 million, and LG&E a long-term debt issuance of $300 million. The Companies included a forecasted interest rate of 3.70% for these issuances. Mr. Baudino has proposed an adjustment to use the "most recent actual Moody's yield for average utility bonds" of 3.40% in calculating the costs associated with the projected issuance.[11] Mr. Baudino alleges that this adjustment is appropriate because "2020 and early 2021 continued a trend of low interest rates" and "[t]he Moody's average utility bond yield on February 25, 2021 was 3.39%."[12]

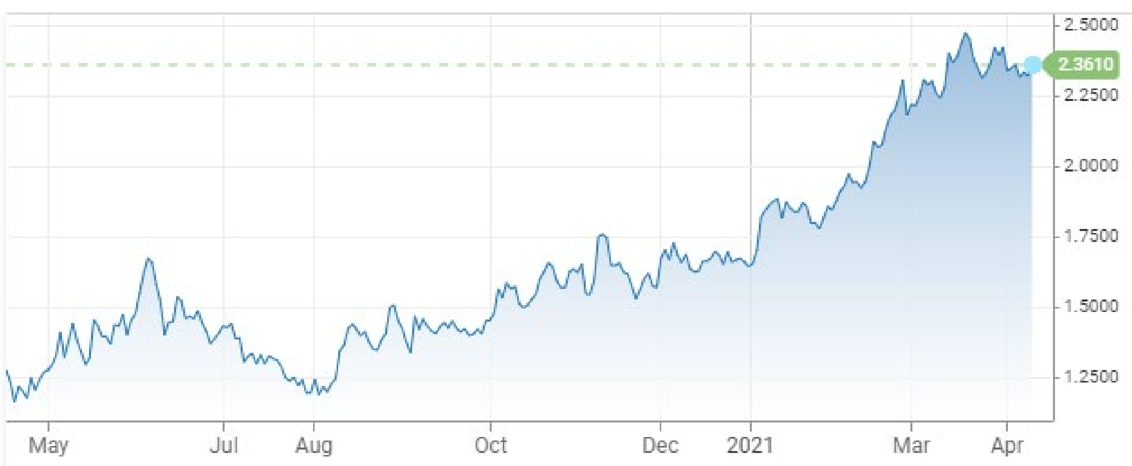
[11] Direct Testimony and Exhibits of Richard A. Baudino on behalf of the Kentucky Office of the Attorney General and Kentucky Industrial Utility Customers, Inc. ("Baudino Direct") dated March 2021 at 40-41.
[12] *Id.* at 41.

Q. Do you agree with Mr. Baudino's adjustment?

A. No, it is unreasonable. Bond yields are not fixed and change daily. Mr. Baudino offers no evidence that the February 25, 2021 average utility bond yield bears any relationship to the forecast bond yield for June 2021. As such, the 3.39% yield on February 25, 2021 is an arbitrarily selected date that is not reflective of known and measurable conditions. Mr. Baudino's selected yield is already stale given the changes in interest rates since February 25.

Q. Can you further describe the volatility in the 30-year Treasury yields?

A. Certainly. The 30-year treasury yields have experienced material volatility in the last year. The graphic below shows the 30-year Treasury yields for the past year. Since the end of 2020, yields have increased more than 65 basis points from 1.65% on December 31, 2020 to 2.32% at the close of business on April 8, 2021.



Q. In your opinion, what caused the significant increase in interest rates since the end of the year?

A. The financial markets have responded to the progress being made in vaccinating the population against COVID-19, and the improving employment trends. The recently passed American Rescue Plan will provide another $1.9 trillion in economic stimulus to the economy over the next few months. Investors are demanding higher interest rates to compensate them for rising inflation risks resulting from these developments. There is a very real possibility of further interest rate increases before June 30, 2021 if the economic news continues to be strong.

Q. What is the Companies' recommendation for the appropriate interest rate to use for the bonds to be issued in the forecasted test year?

A. Rather than selecting the yield on any specific date, the Companies analyzed the expected trends in the yield between the date of the Companies' rate case filing and the beginning of the forecasted test year. The Companies obtained forecasted 30-year treasury yields from several banks in arriving at the 3.70% rate used in the filing. As such, the Companies continue to believe their forecast of 3.70% is reasonable. Mr. Baudino's adjustment is unreasonable and should be denied.

IV. PROPOSED DISALLOWANCES

Q. Please describe Mr. Kollen's proposed disallowances that you will rebut.

A. Mr. Kollen addresses LG&E's proposed increase in Account 868 *Maintenance of Mains* and asks the Commission direct LG&E to defer what he describes as "one-time initial inspection costs" and instead amortize them over 10 years.[13] I will explain why the amortization of these costs is improper.

Q. Please describe LG&E's in-line inspection costs that Mr. Kollen proposes to amortize.

A. Certainly. The enhanced in-line inspections and validation digs are prudently incurred and necessary to comply with federal requirements and safely operate the LG&E gas

[13] Kollen Direct at 100.

system. LG&E has no control over whether to incur the ongoing costs to comply with these requirements. The additional in-line inspections are being performed to provide a better understanding of the threats to each pipeline and the pipeline's condition. Leveraging the knowledge obtained from these inspections enables LG&E to achieve a higher overall level of pipeline safety and supports compliance with ongoing federal pipeline safety reassessment requirements. The need for the enhanced inspections are further described in the rebuttal testimony of Mr. Bellar.

Q. Do you agree with Mr. Kollen's characterization of in-line inspection costs as "one-time" costs?

A. No. As noted in Mr. Bellar's rebuttal testimony at pages 26-27, the ongoing reassessment requirements in federal pipeline safety regulation 49 CFR 192 subpart O and the more stringent pipeline safety requirements imposed by Mega Rule Part 1 are the drivers for the company performing the in-line inspections. LG&E anticipates that in most cases the full suite of expanded in-line inspections will be conducted on a recurring six-year interval for each pipeline. Assessments are completed every year somewhere on the gas system. The actual cost incurred each year fluctuates based on which and how many pipelines are being inspected that year. The use of the in-line inspections will not be a one-time cost; it will be an annual cost in perpetuity. The in-line inspection costs included in the forecasted test year are known, planned, and in some cases, scheduled. These are prudent expenses that should be recovered and amortization of these costs is not appropriate.

V. PENSION AND OPEB EXPENSES

Q. Why does Mr. Kollen argue that actuarial costs are overstated?

A. The Companies presented their pension and OPEB expense—as they have done in every past rate case—using the actuarial calculations prepared by its actuary, Willis Towers Watson. The Willis Towers Watson report dated June 4, 2020 contains projections and estimates for 2021 and 2022. As part of the report, Willis Towers Watson projected that the fair value of fund assets would grow 0.7% in 2020. Because the fund assets grew by more than 0.7% in 2020, Mr. Kollen argues that the Commission should use the actual pension and OPEB expense for calendar year 2020 to set the base revenue requirements in these proceedings instead of the projections from the most recent Willis Towers Watson report. Ironically, Mr. Kollen criticizes the Companies' use of outdated information, and in doing so, asserts the solution is to use even older information. This argument is odd.

Q. What recommendation do you have with respect to the Companies' proposed pension and OPEB expense?

A. In preparing their applications in these cases, the Companies used the best available information at the time to form the projections for pension and OPEB expense. The Companies' actuary firm, Willis Towers Watson, used sophisticated methods to analyze market trends, retirements, and other details of the Companies' workforce to make these projections.

The Companies realize the 2020 investment results varied significantly from the original projections. Normally, final 2021 pension and OPEB expense, prepared by Willis Towers Watson and used in SEC filings, are not available until later in the year. However, the Companies have requested the actuaries to provide updated 2021 projections based on actual 2020 year-end asset values and discount rates.[14] The projections assume an Expected Return on Assets of 7.25% for the pension plan and the assets held in a 401(h) account to satisfy the OPEB liability. The Companies propose to use these 2021 pension and OPEB projections as the new test year estimate for purposes of calculating the revenue requirement. The revised projections are attached as Rebuttal Exhibit DKA-1.[15] The data in Rebuttal Exhibit DKA-1 represents the best and most current information available.

Q. What is the impact of the revised projections?

A. The revised projections reduce the revenue requirements in this case. For LG&E, the pension expense is $3,122,039 (Electric: $2,341,529, Gas: $780,510) lower and OPEB expense is reduced by $870,676 (Electric: $653,007; Gas: $217,669). KU's pension expense is $2,968,377 lower and OPEB costs are down by $939,826.

Q. Is Mr. Kollen an actuary qualified to contest the forecasts and assumptions of Willis Towers Watson?

A. No, not to my knowledge.

Q. Mr. Kollen states that the Companies do not have direct management control over actual pension and OPEB costs. Is this a persuasive reason to adopt Mr. Kollen's proposal?

A. No. Mr. Kollen argues that because the Companies cannot directly control the market performance of the trust fund investments or the mortality experience that affects the pension and OPEB obligations, this creates a ratemaking issue. He identifies the

[14] The projections will be adjusted in May, but the Companies expect any adjustment to be immaterial.
[15] The Companies are proposing to use calendar year 2021 projections for the revenue requirement instead of a test year projection.

ratemaking issue as being due to the volatility of actual pension and OPEB costs, which "cannot be accurately predicted for the year ahead."[16] This ignores the fact that many aspects of the Companies' business are volatile from year to year and thus reliant on the best available projections in a forecasted test year. While the expenses are sometimes higher or lower than projected, the expenses remain a measurable and prudent expense appropriate for recovery.

Mr. Kollen's argument also dismisses the Companies' use of these actuarial calculations in the ordinary course of business. Actuarial calculations are used to calculate pension expense based on relevant inputs that are required to be disclosed in SEC filings including sensitivities thereto. The final calculation of pension and OPEB expense the Companies receive from their actuaries is the expense that is booked for that year. As a further level of oversight, the Companies' independent auditors review the actuarial calculations and assumptions to verify they are reasonable and comparable to other utilities.

I also dispute Mr. Kollen's assertion that the Companies "attempted to forecast the costs for the test year, but biased the result upward by failing to update the trust fund assets to year end 2020."[17] As I previously explained, the Companies' actuary, Willis Towers Watson, prepared those calculations using the best information available at that time. The Companies applications were prepared using the Willis Towers Watson calculation which again was the best available information at the time. The applications were filed on November 25, 2020. The actual results for the year end 2020 were not available until January 21, 2021 or more than eight weeks after the

[16] Kollen Direct at 89.
[17] *Id.* at 90.

applications were filed. The Companies did not "bias the result upward" by using these projections. And the Companies—like so many other investors—could not reasonably foresee the market's performance in 2020. Financial publications have recognized that the 2020 stock market "defied expectations"[18] and is something that could not have been foreseen.[19] His assertion should be given no credence.

Q. Please respond to Mr. Kollen's suggestion that the Commission "set the pension expense included in the base revenue requirement and then direct the Companies to record a regulatory asset or liability for the difference."[20]

A. Mr. Kollen appears to suggest the use of a tracker to record retirement expenses, but there are questions as to how this would apply. The Companies cannot assess such a proposal without additional details.

VI. CONCLUSION

Q. What are your recommendations for the Commission?

A. I respectfully recommend the Commission determine (1) securitization financing is not an available or appropriate solution that should be prescribed in this proceeding as a replacement for updated depreciation rates for the remaining plant balances for the three generating units in question; (2) Mr. Baudino's adjustment to the interest rate on long-term debt is unreasonable; (3) Mr. Kollen's proposed disallowance for inspection costs is unwarranted; (4) Mr. Kollen's proposal to use the Companies' 2020 pension and OPEB expenses should be rejected; and (5) the Companies' revised projected pension and OPEB expenses are reasonable and should be used for ratemaking.

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[18] *2020 Stock Market in Review: A Year That Defied Expectations*, Forbes Advisor, Dec. 14, 2020, available at https://www.forbes.com/advisor/investing/stock-market-year-in-review-2020/.

[19] *Lessons From a Crazy Year in Financial Markets*, The Wall Street Journal, Dec. 31, 2020, available at https://www.wsj.com/articles/lessons-from-a-crazy-year-in-financial-markets-11609410602.

[20] Kollen Direct at 90.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 7th day of April 2021.

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

Rebuttal Exhibit DKA-1 is being provided in a separate file in Excel format.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE YEAR SURCREDIT	))))))))	Case No. 2020-00349

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE YEAR SURCREDIT	))))))))	Case No. 2020-00350

REBUTTAL TESTIMONY OF

ADRIEN M. MCKENZIE, CFA

on behalf of

KENTUCKY UTILITIES COMPANY and
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: April 12, 2021

REBUTTAL TESTIMONY OF

ADRIEN M. MCKENZIE

TABLE OF CONTENTS

GLOSSARY

AG	Kentucky Office of Attorney General
Algonquin	Algonquin Power and Utilities, Inc.
CAPM	Capital Asset Pricing Model
Commission	Kentucky Public Service Commission
the Companies	LGE and KU
DCF	Discounted Cash Flow
DJIA	Dow Jones Industrial Average
DJUA	Dow Jones Utility Average
DOD	United States Department of Defense and Federal Executive Agencies
DPS	Dividends Per Share
ECAPM	Empirical Capital Asset Pricing Model
EPS	Earnings Per Share
ERP	Equity Risk Premium
FERC	Federal Energy Regulatory Commission
FINCAP, Inc.	Financial Concepts and Applications, Inc.
FOMC	Federal Open Market Committee
GDP	Gross Domestic Product
IBES	Institutional Brokers' Estimate System
Joint Intervenors	Mountain Association, Kentuckians For The Commonwealth, the Metropolitan Housing Coalition, and the Kentucky Solar Energy Association.
LGE	Louisville Gas and Electric Company
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
Moody's	Moody's Investors Service
MTB	market-to-book
NYSE	New York Stock Exchange
PSEG	Public Service Enterprise Group
ROE	Return On Equity
RRA	S&P Global Market Intelligence, RRA Regulatory Focus (formerly Regulatory Research Associates, Inc.
S&P	S&P Global Ratings
Supreme Court	United States Supreme Court
Value Line	The Value Line Investment Survey
VSCC	Virginia State Corporation Commission
Zacks	Zacks Investment Research

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q2. ARE YOU THE SAME ADRIEN M. MCKENZIE THAT PREVIOUSLY SUBMITTED PREFILED DIRECT TESTIMONY IN THIS CASE?

A2. Yes, I am.

Q3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A3. My testimony to the Commission addresses the testimony of Mr. Richard Baudino, submitted on behalf of AG/KIUC, and the testimony of Mr. Christopher Walters, submitted on behalf of DOD, concerning the fair ROE that LGE/KU should be authorized to earn on their investment in providing electric and gas utility service. I also address ROE-related testimony from Ms. Lisa Perry, on behalf of Walmart, Inc., and Mr. James Owen, on behalf of Joint Intervenors. While Mr. Baudino and Mr. Walters ultimately accept the common equity ratios of LGE/KU, I also respond to Mr. Walters' contention that LGE/KU's capital structure should be "taken into consideration" in evaluating a fair ROE for the Companies.[1]

Q4. WHAT ROES ARE AG/KIUC AND DOD RECOMMENDING FOR LGE/KU?

A4. Mr. Baudino recommends a 9.00% ROE for the Companies, based on a recommended range of 8.60% to 9.30%. Mr. Walters recommends an ROE of 9.30% for LGE/KU, which is the midpoint of his 9.00% to 9.60% range.

Q5. DO MS. PERRY OR MR. OWEN CONDUCT AN INDEPENDENT EVALUATION OF A FAIR ROE FOR LGE/KU?

A5. No. Neither of these witnesses conduct any analyses of the cost of equity. Their testimony is limited to a presentation of selected data concerning previously

[1] Walters Direct at 25.

authorized ROEs and a discussion of their views concerning ratepayer impacts. Based on this limited review, Ms. Perry expresses her concern that the Companies' 10.0% requested ROE is "excessive."[2] Similarly, Mr. Owen recommends an ROE "towards the lower end of any analysis conducted by Commission Staff."[3]

Q6. WHAT ARE THE PRINCIPAL CONCLUSIONS OF YOUR REBUTTAL TESTIMONY?

A6. The ROE recommendations of Mr. Baudino and Mr. Walters fall below a fair and reasonable level for LGE/KU's utility operations. My rebuttal testimony demonstrates that:

- The ROE recommendations of the other witnesses fall below accepted benchmarks.
- Their discussion of current capital market conditions is incomplete and potentially misleading.
    - Trends in Treasury bond yields do not provide a basis to evaluate changes in the cost of common equity.
    - Higher beta values support the view that the forward-looking risks of electric utility stocks have increased, which implies a higher ROE.
- Mr. Baudino fails to apply sufficient checks of reasonableness to test his DCF results.
- The analyses of AG/KIUC and DOD are undermined by numerous methodological flaws, including:
    - Reliance on a range of historical data that fails to reflect investors' expectations and current capital market conditions.
    - Application of financial models in a manner that is inconsistent with their underlying assumptions.
    - Failure to evaluate model inputs and exclude illogical results.
- Mr. Baudino's and Mr. Walters' rejection of a flotation cost adjustment contradicts the findings of the financial literature and

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[2] Perry LGE Direct at 7.
[3] Owen Direct at 35.

the economic requirements underlying a fair rate of return on equity.

- Mr. Walters' suggestion that the Companies' capital structure implies lower overall investment risk than the electric utility industry is incorrect.

Furthermore, the other witnesses fail to consider the ECAPM approach, which is a recognized ROE method. Finally, their criticisms of my size adjustment, market return calculation, expected earnings approach, and non-utility DCF analysis are without merit. Taken as a whole, these shortcomings ensure that the 9.0% and 9.3% ROE recommendations of AG/KIUC and DOD fall below a fair and reasonable level for the Companies' utility operations.

Q7. HAVE THERE BEEN ANY DEVELOPMENTS SINCE YOUR DIRECT TESTIMONY WAS PREPARED THAT WOULD CAUSE YOU TO MODIFY YOUR RECOMMENDED ROE FOR THE COMPANIES?

A7. No. While the economy and capital markets continue to recover from the impact of the COVID-19 pandemic, risks and uncertainties remain elevated and utility stock prices have yet to reach their pre-pandemic levels. As discussed further in my rebuttal testimony, the increase in utility beta values over the past year is indicative of greater risk and bond yields have increased since the time my testimony was prepared. Thus, I conclude that 10.0% continues to represent a just and reasonable ROE for LGE/KU.

A. Comparison of ROE Recommendation to Accepted Benchmarks

Q8. DO ALLOWED ROES PROVIDE A BENCHMARK TO EVALUATE WHETHER THE RECOMMENDED EQUITY RETURNS IN THIS CASE ARE SUFFICIENT TO MEET REGULATORY STANDARDS?

A8. Yes. Allowed ROEs provide a gauge of the reasonableness of the outcome of a particular analysis or decision, but ROE values do not exist in a vacuum. In considering utilities with comparable risks, investors will always prefer to provide capital to the opportunity with the highest expected return. If a utility is unable to offer a return similar to that available from other investment opportunities posing equivalent risks, investors will become unwilling to supply the utility with capital on reasonable terms.

Q9. HOW DO THE ROE RECOMMENDATIONS OF AG/KIUC AND DOD COMPARE TO ROES AUTHORIZED BY OTHER STATE COMMISSIONS?

A9. Their recommendations are below this standard. As shown below in Table R-1, the average ROE allowed for vertically integrated electric utilities by other state commissions in recent years has been 9.69%:

TABLE R-1
AVERAGE ALLOWED ROE BY STATE COMMISSIONS

Year	Integrated Electric
2017	9.80%
2018	9.68%
2019	9.74%
2020	9.55%
Average	**9.69%**

Source: S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions – January – December 2020, Regulatory Research Associates (Feb. 2, 2021).

As shown on page 3 of Exhibit No. 8 to my direct testimony, at no time during the 46-year period referenced in my risk premium study has the annual average authorized ROE for electric utilities been as low as the values recommended by Mr. Baudino and Mr. Walters in this case.

Similarly, the ROE recommendations of AG/KIUC and DOD fall below the current allowed returns reported to investors for the companies in their respective proxy groups, which average 9.78% (Mr. Baudino) and 9.73% (Mr. Walters). These results are presented on pages 1 and 2 of Rebuttal Exhibit AMM-1.

Of course, the ROEs approved in other jurisdictions do not constrain the Commission's decision-making in this proceeding. However, it is important to understand that there would be a disincentive for investors to provide equity capital if the Commission were to apply a lower ROE to LGE/KU, compared to entities of comparable risk.

Q10. DO THESE ALLOWED ROES CONSIDER THE IMPACT OF RISK-REDUCING REGULATORY MECHANISMS, SUCH AS THOSE APPROVED FOR LGE/KU?

A10. Yes. As indicated in my direct testimony,[4] all the proxy group firms benefit from a wide variety of regulatory provisions that mitigate the impact of earnings attrition and regulatory lag.

Q11. WHAT OTHER BENCHMARK INDICATES THAT THE OTHER PARTIES' RECOMMENDED ROES ARE TOO LOW?

A11. Expected earned rates of return for other utilities provide another useful benchmark of reasonableness. The expected earnings approach is predicated on the comparable earnings test, which developed as a direct result of the Supreme Court decisions in *Bluefield*[5] and *Hope.*[6] This test recognizes that investors compare the allowed ROE with returns available from other alternatives of comparable risk.

Importantly, the expected earnings approach explicitly recognizes that regulators do not set the returns that investors earn in the capital markets. Regulators can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, reference to

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[4] McKenzie Direct at 28-32; Exhibit No. 3.
[5] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) ("Bluefield").
[6] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope").

expected earned rates of return helps ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, MTB ratios, debates over growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q12. HAS THE EXPECTED EARNINGS APPROACH BEEN RECOGNIZED AS A VALID ROE BENCHMARK?

A12. Yes. This method predominated before the DCF model became popular with academic experts, and it continues to be used around the country.[7] A textbook prepared for the Society of Utility and Regulatory Financial Analysts labels the comparable earnings approach the "granddaddy of cost of equity methods" and points out that the amount of subjective judgment required to implement this method is "minimal," particularly when compared to the DCF and CAPM methods.[8][9] The *Practitioner's Guide* notes that the comparable earnings test is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases, as well as sound regulatory economics.[10]

Similarly, *New Regulatory Finance* concluded, "[b]ecause the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful."[11] As

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[7] For example, the Virginia State Corporation Commission is required by statute (Virginia Code § 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in its region. Another example is the Idaho Public Utilities Commission, which also references return on book equity evidence. *See, e.g.,* Order No. 29505, Case No. IC-E-03-13 at 38 (Idaho Public Utilities Commission, May 25, 2004).
[8] At 94.
[9] David C. Parcell, *The Cost of Capital – A Practitioner's Guide*, Society of Utility and Regulatory Financial Analysts (2010) at 115-116.
[10] *Id.*
[11] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 395.

the North Carolina Utilities Commission recently concluded in approving a 9.6% ROE for Duke Energy Carolinas, LLC:

> In prior cases, the Commission has given significant weight to the results of the Expected Earnings methodology, which stands separate and apart from the market-based methodologies (e.g., the DCF or CAPM) also used by ROE experts. The Commission chooses to do so again in this case.[12]

Q13. DOES MR. BAUDINO RECOGNIZE THE ECONOMIC PREMISE UNDERLYING THE EXPECTED EARNINGS APPROACH?

A13. Yes. The straightforward and compelling concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. As Mr. Baudino recognized, economists refer to the returns that an investor must forgo by not being invested in the next best alternative as an "opportunity cost."[13] Mr. Baudino went on to explain that the "investor's opportunity cost is measured by what she or he could have invested in as the next best alternative."[14]

Q14. WHAT ROES ARE IMPLIED BY THE EXPECTED EARNINGS APPROACH FOR THE PROXY GROUPS OF UTILITIES REFERENCED BY MR. BAUDINO AND MR. WALTERS?

A14. The year-end returns on common equity projected by Value Line over its forecast horizon for the firms in the utility proxy group referenced by Mr. Baudino and Mr. Walters are shown on Rebuttal Exhibit AMM-2. As shown on page 1, once adjusted to mid-year, reference to the expected earnings approach implies an average cost of equity for Mr. Baudino's proxy group of utilities of 10.3%. For Mr. Walters' group (page 2), the average implied cost of equity is 10.4%. These

[12] Docket No. E-7, SUB 1187, *et al.*, *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice* (Mar. 31, 2021) at 94.
[13] Baudino Direct at 6.
[14] *Id.*

expected book returns are an "apples to apples" comparison to the 9.0% and 9.3% ROE recommendations supported by Mr. Baudino and Mr. Walters, respectively.

Q15. PLEASE EXPLAIN THE RATIONALE FOR THE ADJUSTMENT TO CONVERT YEAR-END RETURNS TO AVERAGE RETURNS WHEN APPLYING THIS METHOD.

A15. The adjustment factor incorporated in my evaluation of expected returns on Rebuttal Exhibit AMM-2 is required because Value Line's reported returns are based on end-of-year book values. Since earnings are a flow over the year while book value is determined at a given point in time, the measurement of earnings and book value are distinct concepts. It is this fundamental difference between a flow (earnings) and point estimate (book value) that makes it necessary to adjust to mid-year in calculating the ROE. Given that book value will increase or decrease over the year, using year-end book value (as Value Line does) understates or overstates the average investment that corresponds to the flow of earnings. To address this concern, earnings must be matched with a corresponding representative measure of book value, or the resulting ROE will be distorted. This is consistent with use of 13-month average balances utilized by the Companies.

Q16. WHAT ARE THE IMPLICATIONS OF SETTING AN ROE THAT IS BELOW THE RETURNS AUTHORIZED FOR OTHER COMPARABLE COMPANIES?

A16. If the utility is unable to offer a return similar to the returns available from other opportunities of comparable risk, investors will become unwilling to supply capital to the utility on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their cost of capital. Both outcomes violate regulatory standards.

Adopting an ROE for the Companies that is well below the ROEs for comparable utilities could lead investors to view the regulatory framework as unsupportive. Security analysts study regulatory orders to advise investors where to invest their money. Moody's noted that, "[f]undamentally, the regulatory environment is the most important driver of our outlook."[15] Similarly, S&P concluded that "[t]he regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[16] Value Line summarizes these sentiments:

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[17]

In evaluating the Companies' ROE in this case, the Commission has an opportunity to show that it recognizes the importance of continuity and a balanced regulatory regime.

Q17. DO CUSTOMERS BENEFIT WHEN INVESTORS HAVE CONFIDENCE THAT THE REGULATORY ENVIRONMENT IS STABLE AND CONSTRUCTIVE?

A17. Yes. When investors are confident that a utility has supportive regulation, they will make funds available on more reasonable terms, and even in times of turmoil in the financial markets. As noted above, regulatory signals are a primary driver of investors' risk assessment for utilities and changing course from the path of financial strength would be extremely short-sighted. Customers and the service

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[15] Moody's Investors Service, *Regulation Will Keep Cash Flow Stable As Major Tax Break Ends*, Industry Outlook (Feb. 19, 2014).
[16] Standard & Poor's Corporation, *Key Credit Factors For The Regulated Utilities Industry*, RatingsDirect (Nov. 19, 2013).
[17] Value Line Investment Survey, *Water Utility Industry*, January 13, 2017, p. 1780.

area economy enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure reliable service.

The other witnesses' recommended ROEs, especially that of AG/KIUC, are below the norms established for other utilities and would be viewed negatively by investors.

Q18. WHAT OTHER EVIDENCE INDICATES THAT THE ROE RECOMMENDATIONS OF MR. BAUDINO AND MR. WALTERS FAIL TO MEET REGULATORY STANDARDS?

A18. As discussed in my direct testimony, expected rates of return for firms in the competitive sector of the economy are also relevant in determining the appropriate return to be allowed for rate-setting purposes.[18] The idea that investors evaluate utilities against the returns available from other investment alternatives—including the low-risk companies in my Non-Utility Group—is a fundamental cornerstone of modern financial theory. Aside from this theoretical underpinning, any casual observer of stock market commentary and the investment media quickly comes to the realization that investors' choices are almost limitless. It follows that utilities must offer a return that can compete with other risk-comparable alternatives, or capital will simply go elsewhere.

In fact, returns in the competitive sector of the economy form the very foundation for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that the degree of risk, not the nature of the business, is relevant in evaluating an allowed ROE for a utility.[19] The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives, and the

[18] McKenzie Direct at 69-73.
[19] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

total capital invested in utility stocks is only the tip of the iceberg of total common stock investment. My reference to a low-risk group of non-utility companies is consistent with the guidance of the Supreme Court and Mr. Baudino's acknowledgement that "the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms."[20]

Q19. WHAT ARE THE RESULTS OF YOUR ROE ANALYSIS FOR THE NON-UTILITY GROUP?

A19. As shown on page 3 of Exhibit No. 11 to my direct testimony, the average ROEs for the Non-Utility group range from 9.6% to 10.3%. The average of this range is 9.9%. Considering that a comparison of objective risk indicators shows my non-utility group to be less risky than the Electric Group or LGE/KU,[21] this provides a conservative guideline for a fair ROE to the Companies.

Q20. WHAT DO THESE BENCHMARKS YOU DISCUSS IMPLY WITH RESPECT TO MR. BAUDINO'S ROE RECOMMENDATION?

A20. As set forth above, objective consideration of regulatory standards and alternative benchmarks demonstrate that the ROEs supported by AG/KIUC and DOD, and especially the 9.0% recommended by Mr. Baudino, are too low and violate the economic and regulatory standards underlying a fair ROE.

[20] Baudino Direct at 6-7.
[21] McKenzie Direct at Table 7.

B. Implications of Current Capital Market Conditions

Q21. DO MR. BAUDINO AND MR. WALTERS RECOGNIZE THE RECENT DISLOCATIONS THAT HAVE CHARACTERIZED THE ECONOMY AND CAPITAL MARKETS AS A RESULT OF COVID-19?

A21. Yes. Mr. Baudino comments on the turmoil and volatility experienced in capital markets since the onset of the pandemic.[22] He also quotes the Fed's January 27, 2021 statement regarding the pandemic and the U.S. economy:

> The COVID-19 pandemic is causing tremendous human and economic hardship across the United States and around the world. The pace of the recovery in economic activity and employment has moderated in recent months, with weakness concentrated in the sectors most adversely affected by the pandemic.
>
> …
>
> The path of the economy will depend significantly on the course of the virus, including progress on vaccinations. The ongoing public health crisis continues to weigh on economic activity, employment, and inflation, and poses considerable risks to the economic outlook.[23]

As his testimony describes, the threat posed by the coronavirus pandemic has led to extreme volatility in the capital markets, evidenced by sharp declines in the DJUA and the broader market in March 2020, as well as a sharp increase in the Chicago Board Options Exchange Volatility Index (commonly known as the "VIX"). Mr. Baudino notes in his testimony that the DJUA remains depressed and the VIX is currently elevated, relative to their pre-pandemic levels.[24]

Similarly, Mr. Walters notes that the global economy has faced "extraordinary challenges" due to COVID-19, and that "[t]his unprecedented event has impacted all sectors and capital markets."[25]

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[22] Baudino Direct at 14-15.
[23] *Id.* at 10.
[24] *Id.* at 14-15.
[25] Walters Direct at 12.

Q22. HAVE UTILITIES AND THEIR INVESTORS FACED SIMILAR INSTABILITY?

A22. Yes. I discuss this topic in my direct testimony.[26] And while the broader market has fully recovered since the March 2020 selloff and even surpassed pre-pandemic prices, utility stock prices remain depressed. On March 18, 2021 the DJIA was 12% *higher* than its February 18, 2020 level, while the DJUA was 12% *lower*. This divergence between utilities and the broader market is indicative of the lasting effect the COVID-19 pandemic market disruption has had on valuations in the utility sector.

Q23. CAN YOU SUMMARIZE THE FEDERAL RESERVE RESPONSE TO THE ECONOMIC THREAT POSED BY THE CORONAVIRUS PANDEMIC?

A23. I cover much of this area in my direct testimony.[27] The Federal Reserve has lowered its policy rate to close to zero to support economic activity, stabilize markets and bolster the flow of credit to households, businesses, and communities. In addition, they have implemented a broad range of unprecedented programs designed to support financial market liquidity and economic stability.

The Federal Reserve's asset holdings continue to exceed $7.5 trillion, which is an all-time high, and the resulting effect on capital market conditions has likely never been more pronounced. As I previously noted, the Fed currently views the ongoing public health crisis as weighing on economic activity, employment, and inflation, and posing "considerable risks to the economic outlook".[28] While the Federal Reserve's aggressive monetary stimulus may help to ensure market liquidity and support the economy, these actions also support financial asset prices, which in turn place artificial downward pressure on bond yields.

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[26] McKenzie Direct at 15-23.
[27] McKenzie Direct at 18-21.
[28] https://www.federalreserve.gov/newsevents/pressreleases/monetary20210127a.htm

Q24. MR. BAUDINO AND MR. WALTERS CITE PAST DECLINES IN YIELDS FOR U.S. TREASURY SECURITIES.[29] IS THIS THE PROPER FOCUS?

A24. No. While Treasury bond yields provide one indicator of capital costs, they do not serve as a direct guide to the magnitude—or even direction—for changes in the cost of equity for utilities. For example, during times of heightened uncertainty and risk, investors may prefer the relative safety of U.S. government bonds, which can lead to a significant fall in Treasury bond yields while required returns on common stocks are increasing. Treasury bond yields may also be disproportionally impacted by monetary policies, such as quantitative easing, designed with the express intent of artificially suppressing bond yields. FERC has recognized that movements in Treasury bond yields do not provide a reliable guide to changes in required returns for utilities, concluding that, "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."[30]

Q25. MR. WALTERS SUGGESTS THAT INTEREST RATES ARE EXPECTED TO STAY LOW.[31] DO YOU AGREE?

A25. No. More recently, responding to continued monetary and fiscal stimulus measures and expectations for rising inflation, investors have pushed bond yields higher. The table below compares yields in early April 2021 with those prevailing at the time of the hearings in Kentucky Power Company's most recent rate proceeding before the Commission.

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[29] Baudino Direct at 38-39; Walters Direct at 15-20.
[30] *Coakley v. Bangor Hydro-Elec.*, 147 FERC ¶ 61,234 at P 159 (2014).
[31] Walters Direct at 17-20.

TABLE R-2
RECENT INTEREST RATE TRENDS

	(a) Apr-21	(b) Nov-20	Change (bps)
Utility			
Baa	3.63%	3.17%	46
A	3.38%	2.85%	53
Treasury			
10-year	1.73%	0.87%	86
30-year	2.36%	1.62%	74

(a) At April 5, 2021.
(b) Average for November 2020.

Sources
Moody's Investors service (https://credittrends.moodys.com/).
Federal Reserve Bank of St. Louis (https://fred.stlouisfed.org).

Economic forecasters anticipate that yields on Treasury securities will continue to increase significantly over the near-term. For example, the table below presents projections from the most recent long-term forecasts published by Blue Chip, IIS Markit, and Value Line.

TABLE R-3
PROJECTED INTEREST RATE TRENDS

	2021	2022	2023	2024	2025	Change (BP) 2021-25
10-Yr. Treasury						
Blue Chip	1.1%	1.3%	1.7%	2.0%	2.4%	130
IHS Markit	1.2%	1.7%	2.0%	2.2%	2.5%	124
Value Line	1.3%	1.6%	2.0%	2.3%	2.5%	120
30-Yr. Treasury						
Blue Chip	1.8%	2.1%	2.4%	2.8%	3.1%	130
IHS Markit	2.0%	2.4%	2.7%	2.8%	3.0%	104
Value Line	2.0%	2.3%	2.3%	2.5%	2.7%	70
Aaa Corporate						
Blue Chip	2.7%	2.8%	3.2%	3.6%	4.0%	130
IHS Markit	2.3%	2.2%	2.6%	2.8%	3.0%	68
Value Line	2.3%	2.4%	2.8%	3.1%	3.3%	100

Source
Wolters Kluwer, *Blue Chip Financial Forecasts* (Dec. 1, 2020).
IHS Markit, Long-Term Macro Forecast - Baseline (Mar. 1, 2021).
Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 26, 2021).

These forecasts anticipate that interest rates will rise over the period when rates established in this proceeding will be in effect. This evidence suggests that investors continue to anticipate higher interest rates over the near-term, which is consistent with Mr. Baudino's testimony, which notes that the 10-year Treasury bond yield is expected to almost double from 2020 to 2022.[32] This suggests that long-term capital costs—including the cost of equity—will increase over the period when the rates established in this proceeding will be in effect.

Q26. ARE THESE EXPECTATIONS OF HIGHER BOND YIELDS CONSISTENT WITH THE VIEWS OF THE FOMC?

A26. Yes. In conjunction with its most recent policy meeting on March 16-17, 2021, policymakers at the FOMC submitted their projections about where short-term

[32] Baudino Direct at 14.

interest rates are headed. The results are the dot plot—a visual, yet anonymous, representation of where members think rates will go over the short, medium, and longer run. The most recent dot plot indicates that a majority of the FOMC participants expect the midpoint of the target federal funds rate to remain at its present level in 2021.[33] For 2022 and 2023, a minority expect that the target rate will increase. However, over the longer-run horizon of the FOMC's outlook (five to six years), all Fed policymakers on the FOMC expect the federal funds benchmark to be dramatically higher than current levels.[34]

Q27. DO CURRENT BETAS FOR MR. BAUDINO'S PROXY GROUP SUPPORT YOUR ARGUMENT THAT RISKS OF UTILITY COMMON STOCKS HAVE INCREASED?

A27. Yes. Mr. Baudino presents Value Line beta values for the companies in his proxy group, which currently average 0.88.[35] The average Value Line beta value for his proxy group was 0.54 in February 2020. This data shows that the average beta for the proxy group is 63% higher than it was before the COVID-19 pandemic, indicating that the risk of these utilities remains significantly elevated.

Q28. MR. BAUDINO ARGUES THAT THE SHARP INCREASE IN BETAS IS A "SHORT-TERM PHENOMENON" AND WOULD NOT ADVISE "PLACING SIGNIFICANT RELIANCE ON CURRENT BETAS AT THIS TIME."[36] IS THIS A CONSISTENT APPROACH TO CHANGES IN CAPITAL MARKET CONDITIONS BROUGHT ON BY COVID-19?

A28. No. Earlier in his testimony, Mr. Baudino argues that interest rates and the cost of equity for regulated utilities are closely tied, stating that "as interest rates rise, the

[33] *Summary of Economic Projections* (Mar. 17, 2021). https://www.federalreserve.gov/monetarypolicy/files/fomcprojtabl20210317.pdf.
[34] The FOMC members are projecting a midpoint federal funds rate of 2.0% to 3.0%, versus the current level of 0.125%.
[35] Baudino Direct at Exhibit No. (RAB-4).
[36] *Id.* at 36.

cost of equity will also rise, and vice versa when interest rates fall."[37] He goes on to state that "[i]nterest rates have stayed low through 2020" and that "LGE/KU's ROE should reflect their low risk regulated profile as well as the current low interest rate environment."[38] Mr. Baudino cannot have it both ways: he cannot ignore financial market data that points to increased ROEs (*i.e.*, higher betas) while embracing data that might lead to the opposite result. This "cherry picking" approach highlights the downward biases in his ROE estimation process.

Q29. IS THERE ANY MERIT TO MR. BAUDINO'S CONTENTION THAT IT WOULD BE UNREASONABLE TO RELY ON CURRENT BETA VALUES TO APPLY THE CAPM?

A29. No. Mr. Baudino's subjective and unsupported arguments on this issue are incorrect and should be given no weight. The relative price behavior of utility stocks versus the broader market reflects the actual valuation decisions of investors and there is no reason to ignore the implications of this data in applying the CAPM. Value Line's beta values are based on a consistent methodology, and Mr. Baudino presents no evidence to support a finding that this data is inaccurate. Furthermore, Value Line's choice of a five-year period over which to measure beta is an indication that stock price movements going back up to five years, which certainly encompasses the events of March 2020, continue to inform investors' current risk perceptions.

Mr. Walters' assertions that current betas are "abnormally high" or "unlikely to be sustained" are similarly flawed.[39] The fact that beta values for utilities were lower before the COVID-19 pandemic is irrelevant in the context of the CAPM. Setting aside the very real possibility that investors might reasonably

[37] *Id.* at 7.
[38] *Id.* at 20.
[39] Walters Direct at 49-50.

anticipate a recurrence of the current health crisis,[40] the relevance of Value Line's published beta values is not dependent on the assumption that risks affecting common stocks remain consistent with historical relationships. Rather, it is how investors incorporate information into their valuation decisions and ultimately, stock prices that determines risk in the context of modern capital market theory. While the possibility of catastrophic events may be low, investors recognized that they cannot be ruled out and will incorporate this into their determination of required equity risk premiums. Contrary to Mr. Baudino's and Mr. Walters' claims that price movements in response to the coronavirus pandemic are somehow less than "reliable," they form the very foundation of this approach. The only risk at issue in applying the CAPM is the systematic risk reflected in a stock's price movements relative to the entire market, as measured by beta.

Mr. Baudino's suggestion that investors' recent actions can be ignored in favor of "prior history" and Mr. Walters' reference to a historical average beta since 2014 are equally misguided. Ultimately, such suggestions devolve into highly subjective arguments regarding what period might be considered "atypical" and what might be more representative. The reality is that the "true," forward-looking beta is unobservable, and it is impossible to ascertain how investors will react to future information when valuing utility common stocks. That said, recent price movements leading to an increase in utility beta values reflect actual valuation decisions in the market and there is no reason to conclude that this information would not be considered by investors when forming their future expectations. Finally, I note that Mr. Baudino's concerns about current Value Line betas are belied by his ultimate decision to use those very betas in his CAPM analysis.

[40] Already, new lockdowns are being imposed across Europe in attempt to avoid a third wave of the virus, caused in large measure by a more contagious variant of COVID-19.

II. RESPONSE TO MR. BAUDINO

Q30. HOW DOES MR. BAUDINO ARRIVE AT HIS RECOMMENDED COST OF EQUITY?

A30. Mr. Baudino recommends an ROE of 9.00% for LGE/KU, based on a range of 8.60% to 9.30%. Mr. Baudino bases his recommendation exclusively on his application of the constant growth DCF model. While Mr. Baudino includes a CAPM analysis, he elects not to incorporate the results directly in his recommendation.[41] Mr. Baudino applies these methods to the same proxy group I do, but for three utilities that he excludes due to issues that I will discuss later in this testimony.

Q31. WHAT IS YOUR ASSESSMENT OF MR. BAUDINO'S ROE TESTIMONY AND RECOMMENDATION?

A31. Mr. Baudino's recommendation is not realistic. Several specific factors detract from his analysis. First and foremost, Mr. Baudino fails to apply sufficient checks of reasonableness to test his DCF results. His CAPM approach is significantly flawed and he ignores other accepted benchmarks such as the utility risk premium, expected earnings, and ECAPM methodologies, or a review of required returns for non-utility companies. Had Mr. Baudino employed these other approaches, he would have seen that his DCF-based result is by itself not reasonable.

Q32. WHY IS IT CRITICAL TO CONSIDER THE RESULTS OF MULTIPLE APPROACHES WHEN EVALUATING A FAIR ROE FOR THE COMPANIES?

A32. As I discuss in my direct testimony,[42] it customary to consider the results of multiple approaches when evaluating a just and reasonable ROE. It is widely recognized that no single method can be regarded as failsafe; with all approaches

[41] *Id.* at 3-4.
[42] McKenzie Direct at 7-8.

having advantages and shortcomings. Consideration of the results of alternative approaches reduces the potential for error associated with any single quantitative method. The use of multiple cost of equity methods helps mitigate the impact of any temporary market anomalies that may be present in the market data of one company at a particular time. There is also a higher likelihood that random errors from multiple estimates will be offsetting and result in smaller cumulative error than random error from a single estimate.

Q33. DID MR. BAUDINO INCORPORATE THE RESULTS OF MULTIPLE APPROACHES INTO HIS ROE RECOMMENDATION?

A33. No. Mr. Baudino points out that his "recommendation is primarily based on the results of a Discounted Cash Flow ("DCF") model analysis" and that he "did not directly incorporate the results of the CAPM in [his] recommendation."[43] Thus, Mr. Baudino's ROE recommendation is based solely on the output of his DCF model.

Q34. MR. BAUDINO CRITICIZES THE CAPM BECAUSE "A CONSIDERABLE AMOUNT OF JUDGEMENT MUST BE EMPLOYED IN DETERMINING THE MARKET RETURN AND EXPECTED RISK PREMIUM ELEMENTS OF THE CAPM EQUATION."[44] IS THIS A VALID REASON FOR RELYING SOLELY ON THE DCF METHOD FOR SETTING THE ROE?

A34. No. Analytical methodologies such as the DCF model are inherently abstractions of reality. Underlying DCF theory requires any number of assumptions, most of which differ considerably from the situation that confronts actual investors in the capital markets.[45] Furthermore, as the submissions in this proceeding make clear, virtually every element of the DCF model is disputed. The CAPM approach is no

[43] Baudino Direct at 3-4.
[44] *Id.* at 32.
[45] These requirements include a flat yield curve; a constant growth rate; a constant P/E ratio; a constant dividend payout ratio; no stock issuances or purchases; dividends, earnings, book value, and stock price all grow at the same rate; and all of these conditions hold to infinity.

different than the DCF model in these important aspects and is a valuable tool in the ROE estimation process.

As explained in *New Regulatory Finance*, "[r]eliance 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."[46] The Commission clearly can and should consider additional relevant ROE benchmarks, especially during times of turmoil in the economy and capital markets. As *New Regulatory Finance* further explained:

> [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.[47]

The CAPM and other methods are relied on by investors in making their investment decisions and, contrary to Mr. Baudino's position, they have a rightful place in the regulatory process.

Q35. DO YOU HAVE ANY COMMENTS REGARDING MR. BAUDINO'S PROXY GROUP?

A35. Mr. Baudino accepts my proxy group except for three companies. He eliminates Avangrid, Inc. ("AGR") because of its announced plan to acquire PNM Resources, Inc. He also excludes DTE Energy Co. ("DTE") because it has announced its intention to divest itself of its nonutility natural gas company, and DTE reported in February 2021 it was making "significant progress" toward completing the spin-off.[48] These events occurred since I filed my direct testimony and have the potential

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[46] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 428.
[47] *Id.* at 28.
[48] https://www.globenewswire.com/news-release/2021/02/19/2178823/0/en/DTE-energy-reports-significant-progress-toward-completing-spin-off-of-its-midstream-business-DT-Midstream.html

of compromising certain inputs to the ROE estimation models. For these reasons, I do not challenge Mr. Baudino's decision to exclude AGR and DTE.

Finally, Mr. Baudino excludes Algonquin from his proxy group, citing a lack of dividend and earnings growth projections from Value Line and *Yahoo! Finance*.[49] As I discuss in my direct testimony,[50] Algonquin is a North American vertically integrated utility with approximately $10 billion in total assets. It is reasonable for investors to regard Algonquin as a comparable investment alternative that is relevant to an evaluation of the required rate of return for LGE/KU. Although Algonquin is not rated by Moody's, it has been assigned a credit rating of BBB by S&P, which falls within the screening criterion outlined in my direct testimony. There is sufficient publicly available data to include Algonquin in my ROE analyses and so I disagree with Mr. Baudino's exclusion of Algonquin from the proxy group.

A. Discounted Cash Flow Model

Q36. WHAT ARE THE SPECIFIC SHORTCOMINGS THAT YOU HAVE IDENTIFIED IN MR. BAUDINO'S DCF ANALYSIS?

A36. While Mr. Baudino's application of the DCF model is straightforward, there are problems with his approach. First, he includes growth rates in DPS, which are not likely to provide a meaningful guide to investors' current growth expectations.[51] Second, Mr. Baudino averages all the individual growth rates for this proxy group firms and computes a single DCF estimate for each growth rate source. This approach masks the presence of extreme data and biases his results downward.

[49] Baudino Direct at 24-25.
[50] McKenzie Direct at 25.
[51] In fact, Mr. Baudino ultimately elected to ignore these results himself, noting that dividend growth "is significantly lower than the results using forecasted earnings growth rates . . ." Baudino Direct at 37.

Q37. WHY DO YOU TAKE ISSUE WITH MR. BAUDINO'S REFERENCE TO DPS GROWTH RATES?

A37. As documented in my direct testimony, future trends in EPS, which provide the source for future dividends and ultimately support share prices, play the pivotal role in determining investors' long-term growth expectations. The continued success of investment services such as IBES, Value Line, and Zacks, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in EPS is far more influential than trends in DPS. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth].[52]

The availability of projected EPS growth rates also is key to investors relying upon this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of EPS forecasts attests to their relative influence. In fact, Mr. Baudino admits that "Value Line is the only source of which I am aware that forecasts dividend growth."[53]

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[52] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 298.
[53] Baudino Direct at 28.

The fact that analyst EPS growth estimates are routinely referenced in the financial media and in investment advisory publications implies that investors use them as a primary basis for their expectations. As observed in *New Regulatory Finance*:

> The sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Surveys of analytical techniques actually used by analysts reveal the dominance of earnings and conclude that earnings are considered far more important than dividends.[54]

While I do not rely solely on EPS projections in applying the DCF model,[55] my evaluation clearly supports greater reliance on EPS growth rate projections than other alternatives. Similarly, my direct testimony documents the Commission's preference for relying on analysts' growth forecasts, which is supported by the findings of other regulatory agencies.[56]

Growth rates in DPS are not likely to provide a meaningful guide to investors' current growth expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in EPS is far more influential than trends in DPS.

Q38. ARE THERE OTHER PROBLEMS WITH MR. BAUDINO'S DCF ANALYSIS?

A38. Yes. Mr. Baudino's DCF analyses is flawed by his decision to average all individual growth rates across the proxy group and then compute a single DCF

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[54] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 302-303.
[55] As discussed in my direct testimony, I also examined the "br+sv", sustainable growth rates for the companies in my proxy groups. McKenzie Direct at 40-42.
[56] McKenzie Direct at 52-53.

estimate for each growth rate source. Each growth rate represents a stand-alone estimate of investors' future expectations, and each value should be evaluated on its own merits. The fact that an average of several growth rates might produce a DCF estimate that could be considered reasonable does not absolve the need to evaluate each underlying growth rate separately.

For example, consider a utility with a dividend yield of 3.5% and three hypothetical growth estimates of 0.0%, 6.5%, and 14.0%. Under Mr. Baudino's method, the DCF estimate would be computed by adding the 6.8% average of the three individual growth rates to the dividend yield, resulting in a cost of equity estimate of 10.3%. The problem with this method is that it disguises the fact that two of the underlying growth rates—0.0% and 14.0%—do not provide a meaningful guide to investors' expectations. Rather than averaging the good with the bad, each implied cost of equity estimate (in this example, 3.5%, 10.0%, and 17.5%) should be evaluated on a stand-alone basis.[57] Mr. Baudino simply calculates the average of the individual growth rates with no consideration for the reasonableness of the underlying data. Because Mr. Baudino failed to perform this essential step, his DCF analysis included individual growth rates that do not reflect investors' expectations. In the case of Mr. Baudino's DCF application, this resulted in results that are biased downward.

Q39. CAN YOU SHOW THE DOWNWARD BIAS IN MR. BAUDINO'S CONSTANT GROWTH ANALYSIS?

A39. Yes. For example, Mr. Baudino reports an IBES growth rate from *Yahoo! Finance* of 1.77% for Consolidated Edison, Inc.[58] Combining this growth rate with its corresponding dividend yield of 4.14% results in a cost of equity estimate of 5.91%.

[57] The implied cost of equity estimates are calculated as the sum of the dividend yield (3.5%) and the respective growth rates (0.0%, 6.5%, and 14.0%).
[58] Exhibit No. (RAB-3) at 1.

Similarly, combining Avista Corporation's Value Line earnings growth rate of 1.00% with its dividend yield of 4.38% produces an ROE estimate of 5.38%. These implied costs of equity are less than any meaningful threshold. As a result, these illogical growth measures should have been removed from Mr. Baudino's constant growth DCF analysis.

Q40. MR. BAUDINO'S DCF "METHOD 2" UTILIZES MEDIAN GROWTH RATES TO FORMULATE DCF RESULTS.[59] DOES A REFERENCE TO THE MEDIAN IMPROVE HIS DCF ANALYSIS?

A40. No. The median is simply the observation with an equal number of data values above and below. For odd-numbered samples, the median relies on only a <u>single number</u>, *e.g.*, the fifth number in a nine-number set. I believe that each ROE result represents a stand-alone estimate of investors' future expectations, and each value should be evaluated on its own merits. The median does not really consider the results of analysis at all—it is simply a number that splits the distribution of observations into two equal halves. The fact that a median of several outcomes might produce a DCF estimate that could be considered reasonable does not absolve the need to evaluate each underlying return separately. Without considering the underlying data, and by including ROE estimates that do not reflect investor expectations, Mr. Baudino's median approach biases his results downward.

B. Capital Asset Pricing Model

Q41. DO MR. BAUDINO'S CAPM ANALYSES PRODUCE REASONABLE ROE RANGES?

A41. No. Both of Mr. Baudino's CAPM approaches produce outcomes that are so low they should be rejected outright. Results from his forward-looking market risk premium model range from 7.51% to 7.60%, and results from his historical market

[59] Baudino Direct at 28.

risk premium model range from 7.19% to 8.87%.[60] These are far too low to be considered legitimate ROE estimates.

Q42. WHAT IS THE PRIMARY FLAW ASSOCIATED WITH MR. BAUDINO'S HISTORICAL CAPM ANALYSIS?

A42. Mr. Baudino's historical market risk premium approach is backward-looking, whereas the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflect the expectations of actual investors in the market. Mr. Baudino recognizes that:

> **Return on equity analysis is a forward-looking process.** Five-year or ten-year historical growth rates may not accurately represent investor expectations for future dividend growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.[61]

Nevertheless, at least part of Mr. Baudino's application of the CAPM method is based on *historical*—not projected—rates of return (Exhibit RAB-6). Because Mr. Baudino's backward-looking analysis ignores the returns investors are currently requiring in the capital markets, the resulting CAPM estimates fall woefully short of investors' current required rate of return.

Q43. IS THERE GOOD REASON TO DISREGARD THE RESULTS OF HISTORICAL CAPM ANALYSES SUCH AS THOSE PRESENTED BY MR. BAUDINO?

A43. Yes. Mr. Baudino's analysis of historical returns for utility stocks extending back to 1926 does not capture the forward-looking expectations of investors and is unlikely to provide a meaningful indication of the risk premium under current

[60] *Id.*, Table 4, at 37.
[61] *Id.* at 24 (emphasis added).

capital market conditions. Morningstar recognized the primacy of current expectations:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, <u>the expectations of future events are the only factors that actually determine cost of capital</u>.[62]

And while the backward-looking approach used by Mr. Baudino incorrectly assumes that investors' assessment of the relative risk differences, and their required risk premium, between Treasury bonds and common stocks is constant and equal to some historical average, FERC determined that CAPM methodologies based on historical data were suspect because whatever historical relationships existed between debt and equity securities may no longer hold.[63] FERC concluded that historical risk premiums are downward biased given recent trends of low yields for Treasury bonds.[64]

Similarly, the Indiana Utility Regulatory Commission has previously concluded that:

> Relying on historic market returns introduces some highly questionable assumptions, which must be taken on faith. Specificlaly [sic], one must assume that marketplace returns experienced historically are what investors were expecting to receive and continue to guide investor expectations today. It also assumes that asset relationships prevailing over the past 62 years continue today unchanged.[65]

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[62] Morningstar, Ibbotson SBBI, *2013 Valuation Yearbook* at 21 (emphasis added).
[63] *See Orange & Rockland Utils., Inc.*, 40 FERC ¶ 63,053 at 65,208-09 (1987), *aff'd*, Opinion No. 314, 44 FERC ¶ 61,253 at 65,208 (2008).
[64] *See New York Independent System Operator, Inc.*, 146 FERC ¶ 61,043 at P 105 (2014).
[65] Indiana Utility Regulatory Commission, *Indiana Michigan Power Co.*, Cause No. 38728 (Aug. 24, 1990).

As a result, there is every indication that the historical CAPM approach fails to fully reflect the risk perceptions of real-world investors in today's capital markets, and the result should be ignored.

Q44. IS THERE EVIDENCE THAT THE HISTORICAL ANALYSES REFERENCED BY MR. BAUDINO DO NOT REFLECT INVESTORS' EXPECTATIONS?

A44. Yes. The historical equity risk premium findings reported by Mr. Baudino do not make economic sense and contradict his own testimony. For example, Mr. Baudino's Exhibit No. (RAB-5) reveals historical market equity risk premiums of 6.17% and 7.20%. But combining these market equity risk premiums with Mr. Baudino's risk-free rate based on 30-year Treasury bond yield of 1.74%, results in an indicated cost of equity range for the <u>market as a whole</u> of 7.91% to 8.94%, which is less than his ROE recommendation for LGE/KU in this case.

Meanwhile, after noting that beta is the relevant measure of investment risk under modern capital market theory, Mr. Baudino's comparison of beta values in Exhibit No. (RAB-4) indicates that investors' required return on the market as a whole should exceed the cost of equity for electric utilities.[66] Based on Mr. Baudino's own logic, it follows that a market rate of return that does not significantly exceed his own downward biased ROE recommendation has no relation to the current expectations of real-world investors. The fact that much of his CAPM analysis violates the risk-return tradeoff that is fundamental to financial theory clearly illustrates the frailty of Mr. Baudino's analyses.

[66] Baudino Direct at 26-27.

Q45. WHAT IS WRONG WITH MR. BAUDINO'S "FORWARD-LOOKING" CAPM ANALYSIS?

A45. Mr. Baudino adopts a forecasted market return of 8.27% by averaging the median and average projected 3-5 year total market returns from the Value Line Investment Analyzer, February 12, 2021. As with his historical equity risk premium findings, Mr. Baudino's "forward-looking" equity risk premiums do not make economic sense and contradict his own testimony.[67]

Q46. DOES OTHER DATA FROM VALUE LINE REFUTE THE MARKET RETURN RELIED ON BY MR. BAUDINO?

A46. Yes. The dividend yields reported by Value Line for the approximately 1,700 stocks it covers is 1.36%, with the average EPS growth rate being 11.19%.[68] Combining these variables results in an expected return for the market of 12.55%, versus the 8% values relied on in Mr. Baudino's CAPM study.[69]

Q47. MR. BAUDINO ARGUES THAT YOUR ANALYSIS OF THE MARKET RATE OF RETURN SHOULD NOT HAVE BEEN LIMITED SOLELY TO THE DIVIDEND PAYING FIRMS IN THE S&P 500.[70] IS THERE ANY MERIT TO HIS POSITION?

A47. No. As Mr. Baudino recognized,[71] under the constant growth form of the DCF model, investors' required rate of return is computed as the sum of the dividend yield over the coming year plus investors' long-term growth expectations. Because the dividend yield is a key component in applying the DCF model, its usefulness is

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[67] Combining Mr. Baudino's "forward-looking" market equity risk premiums of 5.77% and 6.53% (Exhibit No. (RAB-4)) with Mr. Baudino's risk-free rate of 1.74% results in an indicated cost of equity range for the entire market of 7.51% to 8.27%, which again is significantly less than his ROE recommendation for LGE/KU. Since the proxy group beta (0.88) and the overall market beta (1.00) are not in dispute, Mr. Baudino's market risk premiums in his "forward-looking" CAPM analysis must be fatally flawed.
[68] www.valueline.com, *Value Line Stock Screener* (retrieved Mar. 28, 2021).
[69] Mr. Baudino has previously adopted a similar approach in determining the market rate of return. *See, e.g., Direct Testimony and Exhibits of Richard A. Baudino*, Federal Energy Regulatory Commission, Docket Nos. ER13-1508-001 *et al.* (Oct. 9, 2014) at Exhibit LC-10, page 2.
[70] Baudino Direct at 46.
[71] *Id.* at 22.

hampered for firms that do not pay common dividends. Accordingly, my DCF analysis of the market rate of return properly focused on the dividend paying firms included in the S&P 500.

Q48. WHAT COUNTERPOINT DOES MR. BAUDINO PROVIDE TO ARGUE THAT YOUR 11.6% EXPECTED MARKET RETURN IS OVERSTATED?

A48. Mr. Baudino simply compares his 8.27% market return forecast (based on median expected return of 8.00% and average expected return of 8.54%) from the Value Line Investment Analyzer to the 11.6% expected market return I estimate using forward-looking DCF inputs. But I have already demonstrated that his 8.27% expected market return defies economic logic and is at odds with his own ROE recommendation. Beyond his illogical 8.27% figure, Mr. Baudino offers no evidence that an 11.6% expected market return is overstated.

Q49. ARE THERE OTHER REPUTABLE SOURCES THAT CONFIRM THE DOWNWARD BIAS INHERENT IN MR. BAUDINO'S CAPM MARKET RATE OF RETURN?

A49. Yes. Morningstar, which is a widely recognized source of current investment information, reports a current dividend yield of 1.62% for the S&P 500, with an expected long-term EPS growth rate of 12.22%.[72] This implies an expected rate of return for the S&P 500 of 13.84%, versus the 11.6% used in my application of the CAPM.[73]

[72] Morningstar, *S&P 500 PR*, https://portfolios.morningstar.com/fund/index-summary?t=SPX&region=usa&culture=en-US (last visited Mar. 21, 2021).
[73] McKenzie Direct at Exhibit No. 6.

Q50. DO THE ARGUMENTS ADVANCED BY MR. BAUDINO UNDERMINE THE NEED FOR A SIZE ADJUSTMENT AS PART OF THE CAPM AND ECAPM ANALYSES?

A50. No. Mr. Baudino simply observes that the average beta associated with the lower size deciles examined by Duff & Phelps is greater than the average of his proxy group.[74] While I do not dispute the observation, it has no relevance whatsoever to the implications of Duff & Phelps' findings regarding the impact of firm size. The fact that the average beta for smaller size deciles is greater than for 1.00 says nothing about the range of individual beta values underlying this average.

Moreover, the size premiums are beta adjusted, meaning that the risk impact of beta values (whether higher or lower than Mr. Baudino's proxy group average) have been removed. While the size premiums reported by Duff & Phelps were not estimated on an industry-by-industry basis, this provides no basis to ignore this relationship in estimating the cost of equity for utilities. Utilities are included in the companies used by Duff & Phelps to quantify the size premium, and firm size has important practical implications with respect to the risks faced by investors in the utility industry. As Duff & Phelps concluded:

> Despite many criticisms of the size effect, it continues to be observed in data sources. Further, observation of the size effect is consistent with a modification of the pure CAPM. Studies have shown the limitations of beta as a sole measure of risk. The size premium is an empirically derived correction to the pure CAPM.[75]

Q51. MR. BAUDINO ARGUES THAT A CAPM/ECAPM SIZE ADJUSTMENT DOES NOT APPLY BECAUSE REGULATED COMPANIES "ON AVERAGE ARE QUITE DIFFERENT FROM THE GROUP OF

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[74] Baudino Direct at 47.

[75] Duff & Phelps, *2016 Valuation Handbook, Guide to Cost of Capital*, John Wiley & Sons (2016) at 4-27.

COMPANIES INCLUDED IN THE DUFF AND PHELPS RESEARCH ON SIZE PREMIUMS."[76] IS THIS A VALID CRITICISM?

A51. No. There is no credible basis to conclude that CAPM or ECAPM estimates for utilities are immune from the well-documented relationship between smaller size and higher realized rates of return. The size adjustment required in applying the CAPM and ECAPM is based on the finding that *after controlling for risk differences reflected in beta*, the CAPM overstates returns to companies with larger market capitalizations and understates returns for relatively smaller firms. Of course, there are any number of specific factors that distinguish a utility's risks from other firms in the non-regulated sector, just as there are important distinctions between the circumstances faced by airlines and drug manufacturers. But under the assumptions of modern capital market theory on which the CAPM rests, these considerations are reduced to a single risk measure—beta—which captures stock price volatility relative to the market.

Within the CAPM paradigm, the degree of regulation, the nature of competition in the industry, the competence of management, and every other firm-specific consideration is boiled down to a single question; namely, how much does the stock's price fluctuate in relation to the market as a whole? Beta is the measure of that variability, and research demonstrates that beta does not fully account for the impact of firm size. Duff & Phelps, which is a primary source underlying Mr. Baudino's CAPM applications, concluded that:

> Examination of market evidence shows that within the context of the CAPM, beta does not fully explain the difference between small company returns and large company returns. In other words, the *actual* (historical) excess return smaller companies earn tends to be greater than the excess return *predicted* by the CAPM for these

[76] Baudino at 47.

companies. This 'premium over CAPM' is commonly known as a 'beta-adjusted size premium' or simply "size premium."[77]

Contradicting the incorrect inference Mr. Baudino draws regarding the relative risk of utilities, Duff & Phelps notes that its size premia "have been adjusted to remove the portion of excess return that is attributable to beta, leaving only the size effect's contribution to excess return."[78] In other words, the impact of risk differences between utilities and non-regulated firms is already accounted for and there is no justification to remove the size adjustment on this basis. Confirming the findings of Duff & Phelps, *New Regulatory Finance* observed that "small market-cap stocks experience higher returns than large market-cap stocks with equivalent betas," and concluded that "the CAPM understates the risk of smaller utilities, and a cost of equity based purely on a CAPM beta will therefore produce too low an estimate."[79]

Q52. IS THE SIZE ADJUSTMENT INCORPORATED IN YOUR ANALYSIS CONSISTENT WITH HOW FERC APPLIES THE CAPM?

A52. Yes. FERC has observed that "[t]his type of size adjustment is a generally accepted approach to CAPM analyses,"[80] and includes the size adjustment in the CAPM under its ROE methodology for electric utilities and natural gas and oil pipelines.[81] More recently, FERC affirmed its practice of including a size adjustment, concluding that "the size adjustment is necessary to correct for the CAPM's

[77] Duff & Phelps, *2016 Valuation Handbook, Guide to Cost of Capital*, John Wiley & Sons (2016) at 8-1. Duff & Phelps now publishes the study of historical returns formerly compiled by Morningstar, and previously published by Ibbotson Associates.
[78] Duff & Phelps, 2017 *Valuation Handbook, U.S. Guide to Cost of Capital*, John Wiley & Sons (2017) at 2-10.
[79] Roger A. Morin, *New Regulatory Finance,* Pub. Utils. Reports, Inc. (2006) at 187.
[80] *Coakley v. Bangor-Hydro-Elec. Co.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 117 (2015).
[81] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020); *Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines*, 171 FERC ¶ 61,155 (2020).

inability to fully account for the impact of firm size when determining the cost of equity."[82]

Q53. DOES REFERENCE TO THE IBBOTSON & CHEN OR DUFF & PHELPS HISTORICAL MARKET RISK PREMIUM DATA CITED BY MR. BAUDINO[83] PROVIDE ANY MEANINGFUL CORROBORATION OR GUIDANCE AS TO INVESTORS' REQUIRED RATE OF RETURN?

A53. No. According to Mr. Baudino, this market risk premium data predicts that equity returns for the entire stock market will amount to 7.91% and 8.67%.[84] As I have previously discussed, these figures fall below Mr. Baudino's ROE recommendation for the Companies and below returns authorized for utilities by other state commissions. Considering that these market returns fall so far below ROEs for utilities—which are viewed as less risky than the market as a whole—they are not relevant to the Commission's deliberations.

C. Other ROE Issues

Q54. MR. BAUDINO ARGUES YOUR DCF ANALYSIS IS FLAWED BECAUSE YOU "APPLIED A TEST FOR EXCLUDING ROE RESULTS THAT…WERE TOO LOW BUT FAILED TO EXCLUDE OTHER RESULTS THAT ARE EXCESSIVELY HIGH."[85] IS THIS A VALID ARGUMENT?

A54. No. I evaluate low-end outliers against the observable returns available from long-term bonds. But the fact that there are numerous results that fail this test of reasonableness says nothing about the validity of estimates at the upper end of the

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[82] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-B, 173 FERC ¶ 61,159 at P 100 (2020).
[83] Baudino Direct at 34.
[84] Exhibit No. (RAB-5). Using the current 30-year Treasury Yield data, the market return is 6.17% plus the risk-free rate of 1.74%, or 7.91%. Using the Duff & Phelps "normalized" risk-free rate, the market return is 6.17% plus 2.50%, or 8.67%.
[85] Baudino Direct at 43.

range of results, and there is no basis to discard a corresponding number of values from the top of the range. While upper end cost of equity estimates on the order of 13.6% from my Exhibit No. 4, page 3 may exceed expectations for most utilities, the remaining low-end estimates in the 6.7% to 7.2% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provide a reasonable basis on which to evaluate investors' required rate of return. Mr. Baudino's attempt to recast my DCF analysis including all DCF results,[86] which retains ROE values of 4.9% and 5.2%, is unjustified.

Q55. DOES MR. BAUDINO ADVANCE ANY CREDIBLE CRITICISM OF YOUR GENERAL USE OF A RISK PREMIUM APPROACH?

A55. No. Mr. Baudino's only general observation is that the risk premium method is "imprecise."[87] Of course, this observation applies equally to every model of investor behavior that is used to estimate required returns, including the DCF approach that formed the sole basis for Mr. Baudino's recommendation. The DCF method is only one theoretical approach to gain insight into the return investors require, which is unobservable. The DCF model boils this determination down to the familiar dividend yield and growth rate components, masking the underlying complexities that accompany any attempt to distill every facet of investors' expectations into a single growth estimate. Mr. Baudino's claim that the DCF is "far more reliable and accurate"[88] is unsubstantiated. While the DCF model is a recognized approach to estimating the cost of equity, it is not without shortcomings and does not otherwise eliminate the need to examine the results of other methods. As the Indiana Utility Regulatory Commission noted, for example:

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[86] *Id.* at 43-44.
[87] *Id.* at 39.
[88] *Id.*

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is . . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[89]

Q56. MR. BAUDINO CRITICIZES YOUR USE OF A FORECASTED UTILITY BOND YIELD IN ONE OF YOUR RISK PREMIUM APPLICATIONS. HOW DO YOU RESPOND?

A56. As discussed earlier, widely cited forecasts indicate that bond yields are expected to increase over the intermediate term. Thus, it is prudent to consider a risk premium analysis based on forecast bond yields in addition to one based on historical bond yields. Similarly, in applying the CAPM Mr. Baudino employs a "normalized" risk-free rate that exceeds the yield on 30-year Treasury bonds cited in his testimony by 76 basis points, or an increase of 30%.

Q57. HOW DO YOU RESPOND TO MR. BAUDINO'S DISCUSSION OF YOUR NON-UTILITY ANALYSIS?

A57. Mr. Baudino makes the statement that utilities "have protected markets, e.g., service territories, and may increase the prices they charge in the face of falling demand or loss of customers."[90] Based on this, Mr. Baudino summarily concludes, "Obviously, the non-utility companies face risks that lower risk electric companies like LGE/KU do not face."[91] In fact, however, investors are quite aware that utilities are not guaranteed recovery of reasonable and necessary costs incurred to

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[89] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).
[90] Baudino Direct at 49.
[91] *Id.*

provide service and that there are many instances in which utilities are unable to increase rates to fully recoup reasonable and necessary costs, resulting in an inability to earn the allowed ROE—and potentially even bankruptcy. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return.

The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives, which include all other securities available in the stock, bond, or money markets. Consistent with this view, Mr. Baudino notes the Supreme Court's economic standards and concluded that the fair rate of return on equity should be "comparable to the returns of other firms with similar risk structures."[92] The total capital invested in utility stocks is only the tip of the iceberg of total common stock investment and there are many other "investments of comparable risk" available to investors beyond those in the utility industry.

It is true that utilities are largely sheltered from competition, but they undertake other obligations and lose the ability to set their own prices and decide when to exit a market. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility.[93]

Q58. DOES OBJECTIVE EVIDENCE SUPPORT MR. BAUDINO'S STATEMENT THAT NON-UTILITY COMPANIES ARE OBVIOUSLY MORE RISKY THAN UTILITIES?

A58. No. Investors rely on objective evidence such as credit ratings and beta values to make accurate inferences about risk. The average S&P and Moody's credit ratings

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[92] *Id.* at 6.
[93] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

for the Non-Utility Group referenced in my direct testimony are higher than for the Utility Group or the Companies. The average beta value for the Non-Utility Group is 0.83 as compared to 0.87 for the Utility Group and 1.10 for LGE/KU's parent company, PPL Corp. This assessment is confirmed by the review of financial strength values and other objective indicators of investment risk presented in Table 7 in my direct testimony,[94] which consider the impact of competition and market share and demonstrated that, if anything, the Non-Utility Group could be considered less risky in the minds of investors than the common stocks of the proxy group of utilities.

Q59. MR. BAUDINO SAYS THAT AN ADJUSTMENT TO ACCOUNT FOR FLOTATION COSTS IS NOT NECESSARY SINCE "FLOTATION COSTS ARE ALREADY ACCOUNTED FOR IN CURRENT STOCK PRICES."[95] IS THIS A VALID ASSUMPTION?

A59. No. Mr. Baudino's position is akin to arguing that it is not necessary to reflect the utility's entire reasonable and necessary O&M expense in revenue requirements because such actions would be "accounted for" in the stock price. Flotation costs are legitimate expenses and unless a discrete adjustment is made to recognize them, they will not be recovered in the rate setting process.

III. RESPONSE TO MR. WALTERS

Q60. PLEASE SUMMARIZE YOUR RESPONSE TO MR. WALTERS' ROE TESTIMONY.

A60. There are several serious deficiencies in Mr. Walters' quantitative applications. I demonstrate that his ROE recommendation is biased downward based on the following:

[94] McKenzie at 71.
[95] Baudino Direct at 50.

- Mr. Walters starts with the same proxy group that I use, but then erroneously excludes one company.
- Mr. Walters' DCF approach is weakened because he includes illogical low-end estimates in his results.
- He ignores a readily available and a widely followed source of analysts' growth rates in his DCF methodology.
- He relies on a multi-stage growth DCF model that incorrectly assumes growth in GDP is an upper limit on utility growth.
- His risk premium analysis is flawed because he rejects the well-documented, inverse relationship between equity risk premiums and interest rate levels.
- The CAPM results reported by Mr. Walters are suspect because they are based on market risk premiums that do not reflect the forward-looking expectations of investors, they fail to correct for an observed bias in the CAPM result, and they ignore the impact of company size on expected returns.

Furthermore, his criticisms of my ECAPM, expected earnings and non-utility DCF approaches are without merit. Taken as a whole, these flaws mean that Mr. Walters' recommended ROE falls well below a fair and reasonable level for LGE/KU.

A. Proxy Group

Q61. WHAT IS THE PROBLEM WITH MR. WALTERS' PROXY GROUP?

A61. Mr. Walters starts with the same proxy groups that I use, but then removes one company. He eliminates Algonquin from his proxy group and provides no basis for this exclusion. As I have previously explained, Algonquin is a suitable investment alternative and is of comparable risk to LGE/KU.

Q62. IN RESPONSE TO A DATA REQUEST FROM THE COMMISSION STAFF, MR. WALTERS INDICATES THAT HE EXCLUDED

ALGONQUIN "DUE TO IT NOT BEING BASED IN THE UNITED STATES."[96] IS THIS A VALID REASON?

A62. No. While Algonquin is headquartered in Ontario, Canada, the company's operations are dominated by its U.S. utilities, which accounted for approximately 88% of total revenues during 2020. Algonquin's interim and annual consolidated financial statements are reported in U.S. dollars, its dividend payments are denominated in U.S. dollars, and Algonquin's common shares are listed on the New York Stock Exchange. Mr. Walters' reference to historical index returns for a basket of Canadian stocks are unrelated to the specific circumstances relevant to Algonquin and there is no valid basis to exclude this utility from the proxy group.

B. Discounted Cash Flow Model

Q63. HOW DOES MR. WALTERS APPLY THE CONSTANT GROWTH DCF MODEL?

A63. Mr. Walters applies the constant growth DCF model using forward-looking estimates of EPS growth based on consensus forecasts of securities analysts, as well as considering a sustainable, "br" growth rate. This is comparable to the method discussed in my testimony.

Q64. IS THERE AN OBVIOUS FLAW IN MR. WALTERS' CONSTANT GROWTH DCF ANALYSIS?

A64. Yes. Mr. Walters elected to average all individual growth rates together, and then compute a single DCF estimate for each company. Each growth rate represents a stand-alone estimate of investors' future expectations, and each value should be evaluated on its own merits. Mr. Walters simply calculated the average of the individual growth rates with no consideration for the reasonableness of the underlying data. Because Mr. Walters failed to perform this essential step, his DCF

[96] Response to Staff 1-3.

analysis included individual growth rates that do not reflect investors' expectations and is biased downward.

Q65. IS THERE ANOTHER SHORTCOMING IN MR. WALTERS' CONSTANT GROWTH DCF ANALYSIS?

A65. Yes. Mr. Walters fails to remove illogical values from his final constant growth DCF results.[97] As discussed earlier and in my direct testimony, when applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method. Simply removing the obvious low-end values from the DCF results presented on page 1 of Walters Exhibit CCW-5 (PSEG at 6.32%) increases his constant growth electric DCF average by 16 basis points, from 8.96% to 9.12%.

Q66. DOES MR. WALTERS LEAVE OUT A READILY AVAILABLE, WIDELY RESPECTED SOURCE OF ANALYSTS' GROWTH RATES?

A66. Yes. Mr. Walters failed to include EPS growth rate estimates from Value Line in his analysis. He uses Value Line as an underlying source for many of his calculations, such as to compute the annualized dividend and sustainable growth terms for his DCF models and the average beta for his CAPM studies. Value Line is readily available and is widely followed by investment professionals. It is a well-recognized source of expected growth rates and Mr. Walters' DCF analysis suffers because he does not consider them.

Q67. IN RESPONSE TO A DATA REQUEST FROM THE COMMISSION STAFF, MR. WALTERS SUGGESTS THAT "CONSENSUS ESTIMATES ARE LESS SUSCEPTIBLE TO BIAS OR ERROR THAN ARE ESTIMATES

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[97] For example, Mr. Walters reports a growth rate of 1.15% from *Yahoo! Finance* for PSEG, which equates to a DCF cost of equity using his methodology of 3.65%.

FROM SINGLE ANALYSTS SUCH AS VALUE LINE."[98] IS THIS A VALID REASON TO IGNORE VALUE LINE GROWTH RATES?

A67. No. First, while the growth rates reported by *Yahoo! Finance* and Zacks are presumed to represent a consensus, these sources do not report the number of analyst projections underlying the published growth rates.[99] If the number of analysts were actually key to establishing an estimate's credibility, presumably *Yahoo! Finance* and Zacks would publish this information. In any event, as FERC has correctly noted, IBES growth rates published by *Yahoo Finance!* "may be based on the projection of a single analyst."[100] At the same time, FERC recognized that Value Line estimates are not the product of a single analyst but rather are the product of "a committee composed of peer analysts."[101] This reflects the fact that while the commentary and projections in a Value Line report on an individual firm may be sponsored by a single analyst, the reports are developed under a common, proprietary analytical framework supported by a network of analysts within the Value Line organization, and are reviewed by an internal panel of other analysts prior to publication.

Value Line growth estimates are routinely considered by financial analysts and regulators when applying the DCF model to estimate the cost of equity for utilities. For example, *New Regulatory Finance* endorsed this approach, noting that one way to assess the concern that consensus analysts' forecasts such as IBES may be biased "is to incorporate into the analysis the growth forecasts of independent research firms, such as Value Line, in addition to the analyst consensus forecast."[102]

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[98] Response to Staff 1-5.
[99] *See, eg.,* Exhibit CCW-4 (reporting "Number of Estimates" as "N/A").
[100] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 at P 125 n.278 (2019).
[101] *Id.* at P 125.
[102] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 300.

Q68. WHAT IS THE PROBLEM WITH MR. WALTERS' MULTI-STAGE GROWTH DCF ANALYSIS?

A68. His analysis is not relevant and should be given no weight. There is no merit to Mr. Walters' claim that each company's growth would converge to a single, theoretical maximum sustainable growth rate, as proxied by projected growth for the U.S. GDP. Mr. Walters' multi-stage DCF analysis is not valid and should be ignored.

Q69. MR. WALTERS' MULTI-STAGE DCF MODEL IS BASED ON THE ASSUMPTION OF AN INFINITE STREAM OF CASH FLOWS. WHY WOULDN'T A TRANSITION TO GDP GROWTH MAKE SENSE?

A69. First, this view confuses the theory underlying the DCF model with the practicalities of its application in the real world. While the notion of long-term growth should presumably relate to the specific firm at issue, or at the very least to a particular industry, there are no long-term growth projections available for the companies in the electric utility industry or the broader market. By applying the DCF model in a way that is inconsistent with the information that is available to investors and how they use it, the use of GDP growth places the theoretical assumptions of a financial model ahead of investor behavior. The only relevant growth rate is the growth rate used by investors. Investors do not have clarity to see far into the future, and there is little to no evidence to suggest that investors share the view that growth in GDP must be considered a limit on earnings growth over the long-term.

Second, arguments concerning the sustainability of any individual growth rate for a single firm in the S&P 500 miss the point. The growth rate underlying the market cost of equity represents a weighted average of the expectations for the dividend paying firms in the S&P 500. Within this large group of firms, growth expectations for some firms may be anemic, while projections for other firms are considerably more optimistic. In addition, growth rates for one company may moderate over time, while for others they may increase. Finally, the composition of the S&P 500 is not static. As a result, formerly successful firms are supplanted by new firms with potential for high growth (*e.g.,* Sears is supplanted by Amazon, or Blockbuster is supplanted by Netflix). On balance, however, the growth rates used in my CAPM study are representative of the consensus expectations for the dividend paying firms in the S&P 500 Index as a whole. This contradicts Mr. Walters' position that investors' growth expectations should be constrained by a threshold tied to GDP.

Q70. ARE LONG-TERM GDP GROWTH RATES COMMONLY REFERENCED AS A DIRECT GUIDE TO FUTURE EXPECTATIONS FOR SPECIFIC FIRMS?

A70. No. Certainly, investors consider broad secular trends in economic activity as one foundation for their expectations for a particular industry or firm. But there is no evidence that investment advisory services view GDP growth as a direct guide to long-term expectations for a particular firm – much less every firm in an entire industry.

On the contrary, the financial media typically refers to three-to-five year EPS growth forecasts for individual companies and rarely mentions long-term GDP forecasts. Long-term GDP growth rates are simply not discussed within the context of establishing investors' expectations for individual firms. For example, Value Line reports are routinely relied on as a reliable source of investment data and analysis.[103] But despite Mr. Walters' suggestion that GDP has a fundamental role in shaping investors' growth estimates, Value Line does not even mention trends in

[103] As noted in *New Regulatory Finance*, "Value Line is the largest and most widely circulated independent investment advisory service and influences the expectations of a large number of institutional and individual investors." Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 71.

GDP in its evaluation of the firms in the electric utility industry. Value Line's purpose is to inform investors of the pertinent factors that could affect future expectations specific to each common stock it covers. If the trajectory of GDP growth out to the year 2050 and beyond were directly relevant to investors' evaluation of common stocks, Value Line and other securities analysts would highlight this in their analyses.

Q71. HOW MUCH CONFIDENCE WOULD INVESTORS BE LIKELY TO PLACE ON LONG-TERM GDP PROJECTIONS?

A71. Very little. There are well-understood complexities and inherent inaccuracies involved in forecasting, and such uncertainties are significantly compounded for a long-term time horizon. Consider the example of IHS Markit, which is perhaps the world's foremost econometric forecasting service. IHS Markit publishes GDP projections for the U.S. economy for the next thirty years, but for other important economic variables (*e.g.*, bond yields) their forecast simply holds projected values constant after a five-year horizon.

Q72. ARE THERE ACADEMIC STUDIES THAT RECOGNIZE THE SHORTCOMINGS OF ADOPTING A GENERIC LONG-TERM GROWTH RATE, SUCH AS GDP GROWTH?

A72. Yes. Professor Myron J. Gordon, who pioneered the application of the DCF approach, concluded that reference to a generic long-term growth rate, such as Mr. Walters advocates, was unsupported.[104] More specifically, Dr. Gordon concluded that any assumption of a single time horizon for a transition to a generic long-term growth rate was highly questionable and failed to reduce error in DCF estimates. Instead, Dr. Gordon specifically recognized that, "it is the growth that investors expect that should be used" in applying the DCF model, and he concluded: "A

[104] Myron J. Gordon, "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* (1974) at 100-01.

number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[105]

Similarly, a subsequent paper co-authored by Professor Gordon concluded that "[a]nalysts do not predict earnings beyond five years, which suggests that any consensus of opinion among investors probably deteriorates quickly after five years."[106] Professor Gordon further concluded that "the consensus among investors is that the future has a finite horizon of approximately seven years."[107] Meanwhile, a study reported in the *Journal of Investing* determined that there is no correlation between stock market returns or earnings growth and GDP, suggesting that investors' expectations built into observable share prices are driven by valuation measures, and not expected economic growth.[108] In other words, reference to long-term forecasts of GDP growth in applying the DCF model is inconsistent with investor behavior.

Q73. IS THERE EVIDENCE THAT USING MR. WALTERS' LONG-TERM GDP GROWTH RATE WILL UNDERSTATE INVESTORS' EXPECTATIONS?

A73. Yes. Actual historical growth rates for individual firms in Mr. Walters' proxy group again refute the notion that long-term growth is constrained by GDP. For example, Value Line reports that almost one-half of the companies included in its electric utility industry group achieved earnings growth over the last 10 years that exceeded Mr. Walters' 4.35% GDP growth rate.[109] These values indicate that firms can and do achieve long-term growth far higher than the GDP growth rate used by Mr. Walters.

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[105] *Id.* at 89.

[106] Joseph R. Gordon and Myron T. Gordon, *The Finite Horizon Expected Return Model*, Financial Analysts Journal (May-Jun. 1997) at 52-61.

[107] *Id.*

[108] Joachim Klement, "What's Growth Got to Do with It? Equity Returns and Economic Growth," *Journal of Investing,* Vol. 24, No. 2 (Summer 2015): 74:78.

[109] www.valueline.com (retrieved Mar. 17, 2021). *See* Exhibit CCW-10.

Q74. ARE THERE COMPUTATIONAL ERRORS THAT ALSO BIAS MR. WALTERS' MULTI-STAGE DCF COST OF EQUITY ESTIMATES DOWNWARD?

A74. Yes. As noted above, under his multi-stage DCF approach Mr. Walters predicted the cash flows that would accrue to investors over the next 200 years. To arrive at his estimated cost of equity, Mr. Walters used the internal rate of return ("IRR") function available in Microsoft's Excel spreadsheet program to determine the discount rate (*i.e.*, investors' required rate of return) that would equate these cash flows with the current market price of the stock.[110] This IRR calculation, however, assumes that annual cash flows are received at the end of each year, which is inconsistent with the periodic dividend payments that investors receive over the course of the year and results in a downward bias in the implied cost of equity.

C. Utility Risk Premium

Q75. DO THE RESULTS OF MR. WALTERS' RISK PREMIUM APPROACH BASED ON AUTHORIZED RETURNS PROVIDE A RELIABLE GUIDE TO A FAIR ROE FOR LGE/KU?

A75. No. Mr. Walters' risk premium analysis is fatally flawed because he fails to incorporate the inverse relationship between interest rates and equity risk premiums in his analysis of historical authorized rates of return. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums decrease, and when interest rates are relatively low, equity risk premiums are greater. Contradicting Mr. Walters' assertions,[111] this inverse relationship between

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[110] Walters public workpaper: "Exhibits CCW-2 - CCW-9 and CCW-15 - CCW-16 (Electric).xlsx," at sheet "CCW-9 (Pg1)" and "Exhibits CCW-2 - CCW-7, CCW-9 and CCW-15 - CCW-16 (Gas).xlsx" at sheet "CCW-9 (pg4)."

[111] Walters Direct at 75.

equity risk premiums and interest rates has been widely reported in the financial literature. As summarized in *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[112]

New Regulatory Finance noted that, taken together, studies in the financial literature imply that a 100 basis point decrease in bond yields would imply a 50 basis point increase in the equity risk premium.[113]

As shown on Walters Exhibits CCW-12 and CCW-13, current interest rates are lower than those prevailing over the years covered by his study, including the five-year period used to derive his risk premium results. Given that interest rates are lower than those during his study period, current equity risk premiums should be relatively higher, which Mr. Walters' analysis ignores.

Q76. WHAT OTHER FLAWS ARE ASSOCIATED WITH MR. WALTERS' RISK PREMIUM APPLICATION?

A76. Mr. Walters subjectively chooses to truncate the data available to apply his risk premium approach by ignoring all observations prior to 1986, and ultimately relies on data for just the 2016 to 2020 period. Other than asserting that his study "need not encompass a very long historical time period,"[114] Mr. Walters offers no meaningful explanation to ignore available data. By choosing a truncated period for his risk premium study, Mr. Walters unnecessarily introduces the potential for subjective bias that undermines the credibility of his analysis. Ibbotson Associates noted the pitfalls of such a subjective approach:

[112] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 128.
[113] *Id.* at 129.
[114] Walters Direct at 44.

> Some analysts estimate the expected risk premium using a shorter, more recent time period on the basis that recent events are more likely to be repeated in the near future … This view is suspect …[115]

Mr. Walters attempts to differentiate his risk premium analysis from studies of historical rates of return,[116] but this is a distinction without a difference. In both cases, historical averages are used as proxies for future expectations. Coupled with his failure to account for changes in risk premiums related to the level of bond yields, Mr. Walters' failure to consider the entire scope of available data seriously undermines his analysis.

Q77. ARE THERE OTHER INCONSISTENCIES IN MR. WALTERS' RISK PREMIUM APPROACH?

A77. Yes. In applying the risk premium approach based on 30-year Treasury bonds, Mr. Walters elected to use a *projected* bond yield of 2.10%, whereas his application using A-rated and Baa-rated utility bond yields relied on *historical* 13-week averages. As discussed earlier, reliance on projected bond yields, as Mr. Walters did when referencing Treasury bonds, better reflects investors' expectations.

Q78. WHAT RISK PREMIUM RESULTS ARE IMPLIED BY MR. WALTERS' 2016-2020 STUDY PERIOD AFTER CORRECTING THESE SHORTCOMINGS?

A78. This analysis is presented on Rebuttal Exhibit AMM-3. As shown there, I have calculated the inverse relationship between bond yields and the three series of equity risk premiums over the 2016-2020 study period chosen by Mr. Walters. I have also consistently used projected bond yields by adding the 13-week average yield spreads supported in Mr. Walters' testimony to his projected 2.10% Treasury yield. This corrected analysis indicates an ROE in the range of 9.5% to 9.8%, which

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[115] Ibbotson Associates, *2005 Yearbook, Valuation Edition* at 80.
[116] Walters Direct at 44.

confirms that Mr. Walters' risk premium results and his ultimate ROE recommendation are both biased downward.

D. Capital Asset Pricing Model

Q79. WHAT ARE THE WEAKNESSES IN MR. WALTERS' CAPM STUDIES?

A79. Mr. Walters' CAPM studies have several shortcomings. Most significantly, Mr. Walters constructs a flawed beta based on stale historical averages, and his market risk premium is distorted by his reliance on historical returns since 1926 and a two-step DCF approach. Finally, like Mr. Baudino, he fails to correct for an observed bias in the CAPM result and his analysis ignores the impact of company size on expected returns.

Q80. WHAT IS THE PRIMARY DIFFERENCE BETWEEN MR. WALTERS' CAPM ANALYSIS BASED ON HIS SO-CALLED "RISK PREMIUM METHOD" AND THE APPROACH DESCRIBED IN YOUR DIRECT TESTIMONY?

A80. As Mr. Walters observes, the appropriate market return ("R_m") to use in applying the CAPM is the "[e]xpected return for the market portfolio."[117] The fundamental difference between my approach and that of Mr. Walters is that, while my analysis looks to the future return expectations of investors in the capital markets, Mr. Walters' CAPM under his "risk premium methodology" is based almost entirely on historical data. As Mr. Walters explains:

> I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market.[118]

[117] Walters Direct at 47.
[118] *Id.* at 50 (emphasis added).

In other words, the relatively small portion of Mr. Walters' "forward-looking" market return constituting inflation is based on projected data, but the actual return on the market itself is completely backward-looking.

As a result, this approach is inconsistent with the assumptions of the CAPM because, as noted above, the CAPM is predicated on the forward-looking expectations of investors. Mr. Walters' use of historical returns in the CAPM is inconsistent with the underlying presumptions of the model.

Q81. IS MR. WALTERS' DCF-BASED MARKET RISK PREMIUM ANY MORE RELIABLE?

A81. No. Mr. Walters' application of the DCF model to develop a market risk premium for the CAPM is compromised because his analysis relied on a "two-step" form of the DCF model premised on a transition to GDP growth for every firm in the economy.

Q82. IS MR. WALTERS JUSTIFIED IN ADOPTING FERC'S TWO-STEP DCF METHOD TO ESTIMATE THE MARKET RATE OF RETURN?

A82. No. I addressed the fallacies of reference to GDP growth in applying the DCF method earlier. Suffice to say that even FERC has rejected the idea that its two-step DCF approach represents a credible basis on which to estimate the market risk premium necessary for the CAPM, concluding that "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 . . . used to develop the market risk premium for [the] CAPM analysis."[119] Arguments for using the two-step DCF model to estimate the market rate of return have been raised extensively in FERC proceedings and consistently rejected.[120] As FERC recently

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[119] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531-B, 150 FERC ¶ 61,165 at P 113 (2015).
[120] *See, e.g., Assoc. of Bus. Advocating Tariff Equity, et al.*, Opinion No. 551, 156 FERC ¶ 61,234 at P 170 (2016); *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.,* Opinion No. 569-A, 171 FERC ¶ 61,154 at P 85 (2020).

concluded, "We also continue to find that the CAPM should use a one-step DCF for its risk premium."[121]

Q83. IS MR. WALTERS JUSTIFIED IN REFERENCING AVERAGES OF VALUE LINE BETA VALUES PUBLISHED BACK TO 2014?

A83. No. I addressed the use of stale beta values earlier in my response to Mr. Baudino. Strictly speaking, the beta value used to apply the CAPM is also a forward-looking measure of the relative volatility of each stock in relation to the entire market. Recognizing that it is not possible to estimate this parameter on a forward-looking basis, it is customary to reference historical price data over a recent historical period (e.g., five years) as a proxy for this relationship. But the fact that this calculation necessarily relies on historical data does not justify Mr. Walters' reference to stale beta values sourced from Value Line publications back to 2014. As Mr. Walters recognized, "Contemporary market conditions can change dramatically,"[122] and there is no basis to ignore the implications of recent changes when applying the CAPM.

Q84. MR. WALTERS ARGUES THAT IT IS THEORETICALLY INCORRECT TO APPLY THE CAPM USING VALUE LINE BETAS AND A MARKET RETURN BASED ON THE S&P 500.[123] WHAT IS THE CRUX OF HIS ARGUMENT?

A84. Mr. Walters asserts that "[b]etas employed in a CAPM should be calculated using the benchmark index that is also used as a proxy for the overall market."[124] Mr. Walters states, "Mr. McKenzie and I both relied on the S&P 500 as the proxy for the overall market," and notes that Value Line calculates its beta values based on a comparison of each stock's volatility relative to the NYSE. Mr. Walters does not

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[121]. *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.,* Opinion No. 569-A, 171 FERC ¶ 61,154 at P 85 (2020).
[122] Walters Direct at 43.
[123] *Id.* at 66.
[124] *Id.*

dispute the accuracy of Value Line's calculated beta values, but he argues that my reliance on Value Line betas is "at odds" with my reference to the dividend-paying firms in the S&P 500 as the market benchmark.[125]

Q85. DO YOU AGREE WITH THIS INFERENCE?

A85. No. Under the CAPM, the volatility at issue theoretically relates the market price of the stock with the market price of every other possible investment opportunity in the "market," including collectible cars and gold bullion. Just as it is not possible to precisely define the growth expectations necessary to apply the DCF model directly to utilities, forward-looking market returns and beta values are unobservable. Application of the DCF approach to the dividend-paying firms in the S&P 500 provides a sound proxy for investors' expected return on the "market." Similarly, reference to Value Line's published beta values also offer an objective proxy for an unobservable, forward-looking beta. There is no "mismatch," as Mr. Walters seems to imply.

Mr. Walters' contention is further disproved by reference to studies in the financial research. *Marston and Harris* noted that it derived an estimate of the market rate of return for a sample of approximately 400 companies selected from the S&P 500, while the beta values used in the study were calculated "against . . . all NYSE securities."[126] This approach, used by recognized researchers in a peer-reviewed journal sponsored by the Eastern Finance Association, mirrors my CAPM approach. Similarly, in applying a market rate of return based on the dividend paying firms in the S&P 500, the Staff of the Illinois Commerce Commission also relied on published betas from Value Line.[127] FERC also uses Value Line betas

[125] *Id.* at 64

[126] Felicia Marston and Robert S. Harris, *Risk and Return: A Revisit Using Expected Returns*, Fin. Review (Feb. 1993) ("*Marston & Harris*"). Value Line betas are also derived based on weekly percentage changes in the New York Stock Exchange Average.

[127] *Direct Testimony of Rochelle Langfeldt*, Illinois Commerce Commission, Docket No. 01-0432 (2001), at 27 (citing "[t]he average Value Line adjusted beta for the Electric sample.").

with the same methodology I adopted to estimate the overall market return and has rejected arguments identical to that raised by Mr. Walters here.[128]

Q86. IS THERE OTHER EVIDENCE THAT UNDERCUTS MR. WALTERS BETA INCONSISTENCY ARGUMENT?

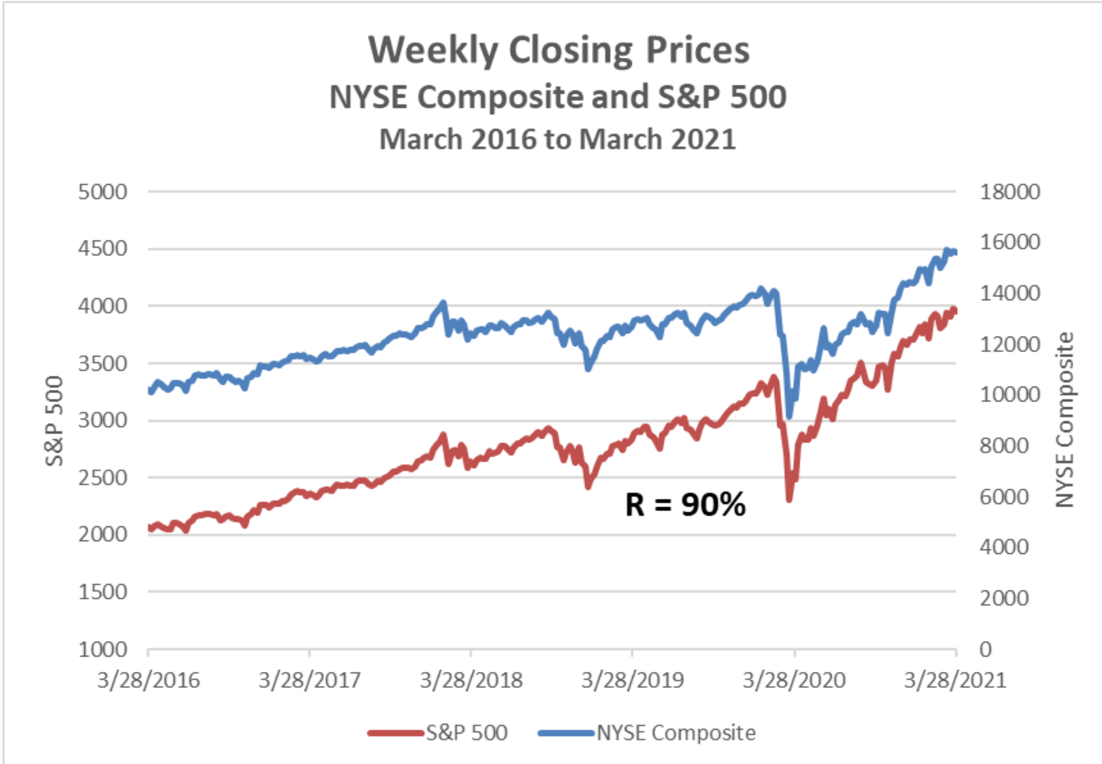
A86. Yes. Beta measures the variability of the price of a common stock relative to the broader market. While it is possible to calculate this measure of relative price volatility using alternative market benchmarks (i.e., NYSE Composite or S&P 500), to the extent that movements in market indices are driven by the stock prices of very large capitalization companies and thus move in tandem, the beta values using similar time periods would be indistinguishable. If there is no systemic difference in the relative movements of the NYSE Composite and the S&P 500, then there is no basis to suggest that a beta calculated against the NYSE Composite would not apply equally to a market rate of return estimated by reference to the S&P 500.

The degree to which movements in the NYSE Composite and S&P 500 are synchronized can be tested through correlation analysis. The correlation coefficient measures the degree that two variables move together. A correlation coefficient of 0.0 would indicate that there is no consistent co-movement between two variables, while a correlation coefficient of 1.0 would indicate perfect correlation, i.e., that 100% of the change in one variable is reflected in the other variable.

Figure R-1 displays the weekly percentage changes in the NYSE Composite and the S&P 500 over the five-year period ending March 31, 2021:

[128] *See, e.g., Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.,* Opinion No. 569-A, 171 FERC ¶ 61,154 at P 75 (2020); *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.,* Opinion No. 569-B, 173 FERC ¶ 61,159 at PP 100, 101 (2020).

FIGURE R-1



As indicated on the chart, this analysis results in a correlation coefficient of 0.90, meaning that weekly changes for the NYSE Composite are almost perfectly matched by similar movements in the S&P 500. The high degree of correlation between movements in the NYSE Composite and movements in the S&P 500 undercuts Mr. Walters' allegation of a "mismatch" between Value Line betas and a market return predicated on a subset of the S&P 500.

Value Line is recognized as being the most widely available source of investment information to investors, and there are many citations to textbooks and other sources supporting its usefulness as a guide to investors' expectations.[129] Coupled with the administrative benefits associated with reliance on beta values from Value Line, including a consistent methodology by an independent third-party

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[129] *See, e.g.*, Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 71 ("Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors.").

and immunity to selective changes in assumptions, my evidence supports continued reference to Value Line's published beta values in applying the CAPM approach.

Q87. DO THE MARKET RETURNS PRESENTED IN TABLE 10 TO MR. WALTERS' DIRECT TESTIMONY PROVIDE ANY MEANINGFUL SUPPORT FOR THE UNDERLYING ASSUMPTIONS OF HIS CAPM ANALYSES?

A87. No. The market returns presented in this table range from -0.10% to 7.10% and fall far below the bottom end of Mr. Walters' recommended ROE range for LGE/KU. Considering that the investment risks of the Companies are lower than those of the entire market, this nonsensical result clearly suggests that the Commission should give no weight to Mr. Walters' comparison.[130]

Q88. WHAT ABOUT MR. WALTERS' CRITICISM THAT YOUR FORWARD-LOOKING ESTIMATE OF THE MARKET RATE OF RETURN IS NOT REASONABLE?[131]

A88. As noted earlier, the use of forward-looking expectations in estimating the market risk premium is well accepted in the financial literature and has been recognized by other regulators. Mr. Walters' criticism of the 10.2% market rate of return used in my CAPM and ECAPM studies is perplexing, given that it falls below the midpoint of the 9.1% to 12.5% range supported by his own testimony.[132]

Q89. MR. WALTERS ARGUES THAT CERTAIN OF THE GROWTH RATES UNDERLYING YOUR DCF STUDY FOR THE S&P 500 "DO NOT MAKE LOGICAL SENSE FROM AN ECONOMIC PERSPECTIVE."[133] DOES YOUR ANALYSIS DEPEND ON AN ASSUMPTION THAT THE

[130] Mr. Walters cites a "Markets Observer" report from Morningstar in support of an expected return of -0.10 percent for large cap equities, but as documented in footnote 91, Morningstar's current projections imply an expected rate of return for the S&P 500 of 13.84%,

[131] Walters Direct at 64-65.

[132] Walters Direct at 55 (*noting*, "My market risk premium estimates are in the range of 9.1% to 12.5%.").

[133] *Id.* at 64.

INDIVIDUAL GROWTH RATES FOR EACH FIRM WILL BE CONSTANT FOREVER?

A89. No, not at all. As discussed earlier in this testimony, arguments concerning the "sustainability" of any individual growth rate for a single firm in the S&P 500 miss the point. We are not calculating the cost of equity for an individual firm and assuming that growth rate will be constant for perpetuity. Rather, the growth rate underlying the market cost of equity represents a weighted average of investors' expectations for the dividend paying firms in the S&P 500 *index*. My evidence contradicts Mr. Walters' regarding the "sustainability" of individual growth rates.

Q90. IS MR. WALTERS INCONSISTENT IN HIS ATTACKS ON THE GROWTH RATES YOU USE IN DETERMINING THE EXPECTED MARKET RETURN?

A90. Yes. He says:

> Mr. McKenzie's expected return on the market of 11.6% is based on a dividend yield of 2.3% and an expected growth rate of 9.2%. The expected growth rate of 9.2% incorporated in his expected market return is more than twice the expected growth rate of the economy of 4.35%.[134]

An investigation of the growth rates embedded in the market returns that Mr. Walters' relies on for six out of his nine CAPM approaches reveal that they are higher than the 9.2% value that I use. The growth rate he applies in determining his DCF Based MRP is 12.83%; the blended growth rate included in his FERC 2-Step Based MRP is 11.13%. Mr. Walters' criticism of my weighted market return growth rate as too high makes no sense, given that it falls below values that he relies on.

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[134] *Id.*

Q91. DOES MR. WALTERS FAIL TO CONSIDER OTHER IMPORTANT FACTORS IN APPLYING THE CAPM?

A91. Yes. Like Mr. Baudino, Mr. Walters fails to reflect the size adjustment in his CAPM application.

Q92. IS THERE ANY MERIT TO MR. WALTERS' CONTENTION THAT A SIZE ADJUSTMENT SHOULD NOT BE APPLIED TO UTILITIES?[135]

A92. No. I addressed the relevance of the size adjustment previously. As I demonstrated, the fact that the size premiums reported by Duff & Phelps were not estimated on an industry-by-industry basis provides no basis to ignore this relationship in estimating the cost of equity for utilities. Utilities are included in the companies used by Duff & Phelps to quantify the size premium, and firm size has important practical implications with respect to the risks faced by investors in the utility industry. As FERC recently concluded, "[We] disagreed with intervenors that the utility industry is unique, and that the size premium adjustment would therefore be inapplicable, as the size premium adjustments are supported by a robust data set."[136]

Q93. MR. WALTERS REJECTS YOUR USE OF THE ECAPM BECAUSE HE SAYS IT AMOUNTS TO DOUBLE COUNTING WHEN USED WITH VALUE LINE ADJUSTED BETAS.[137] WHAT IS YOUR RESPONSE?

A93. As I state in my direct testimony, the ECAPM is simply a variant of the traditional CAPM approach that is designed to correct for an observed bias in the CAPM result. The modification reflected in the ECAPM is distinct from the Value Line adjustment of estimated betas for the demonstrated tendency to regress toward the mean. The ECAPM reflects a refinement to adjust for a systematic tendency of low beta portfolios to over-earn and high beta portfolios to under-earn relative to the

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[135] Walters Direct at 66-68.

[136] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.,* Opinion No. 569-A, 171 FERC ¶ 61,154 at P 63 (2020)

[137] Walters Direct at 69-73.

predictions of the CAPM capital market line. In other words, even if a firm's beta value is estimated with perfect precision, the CAPM would still understate the return for low-beta stocks and overstate the return for high-beta stocks.[138] The ECAPM and the use of adjusted betas represent two separate and distinct issues in estimating returns, and both are useful for improving the traditional CAPM results.

E. Other ROE Issues

Q94. MR. WALTERS ACCUSES YOU OF "MANIPULATING" YOUR DCF RESULTS BECAUSE YOU REMOVED A NUMBER OF LOW-END AND HIGH-END ESTIMATES.[139] IS THIS A VALID CRITICISM?

A94. No. I evaluate low-end values against the observable returns available from long-term bonds. But as discussed earlier, the fact that there are numerous results that fail this test of reasonableness says nothing about the validity of estimates at the upper end of the range of results, and there is no basis to discard an equal number of values from the top of the range.

Q95. HAS A SIMILAR APPROACH BEEN ADOPTED BY COMMISSION STAFF WITNESSES?

A95. Yes. In recent testimony before the Maryland Public Service Commission, Staff witness Drew McAuliffe eliminated low-end cost of equity estimates below 6.5%, as well as high-end values above 14.0%. As Mr. McAuliffe concluded:

> I exclude companies with an ROE below a lower bound of 6.5 percent because I believe a return below that level would be too close to [the utility's] cost of debt to be attractive to an equity

[138] Furthermore, there is academic support for the use of adjusted betas in alternative versions of the CAPM. For example, *On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital* noted that "[t]he assertion that risk premiums are proportional to NYSE betas is shown to result in downward (upwards) biased predictions of the cost of equity for a public utility having a NYSE beta that is less (greater) than unity," and concluded that adjusted betas, such as those published by Value Line, are "better predictors than are unadjusted betas." Robert Litzenberger, Krishna Ramaswamy, and Howard Sosin, *On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital*, 369-393 Journal of Finance (May 1980).

[139] Walters Direct at 62.

> investor. . . . Companies with ROE's [sic] above 14 percent were removed because these returns are far out of line with the return awarded in recent base rate cases.[140]

The DCF results that I excluded on page 3 of Exhibit No. 4 to my direct testimony ranged from 4.9% to 6.4%, with the highest value being 13.6%.

Q96. MR. WALTERS SUGGESTS THAT USING THE MEDIAN WOULD BE A BETTER APPROACH THAN REMOVING OUTLIERS IN DEALING WITH EXTREME DCF RESULTS.[141] DO YOU AGREE?

A96. No. Like my earlier discussion of Mr. Walters' DCF averaging technique, I believe that each ROE result represents a stand-alone estimate of investors' future expectations, and each value should be evaluated on its own merits. The median does not really "consider" the results of analysis at all—it is simply a number that splits the distribution of observations into two equal halves. The fact that a median of several outcomes might produce a DCF estimate that could be considered reasonable does not absolve the need to evaluate each underlying return separately. Without considering the underlying data and by including ROE estimates that do not reflect investor expectations, Mr. Walters' median approach biases his results downward.

Q97. MR. WALTERS CONTENDS THAT THE EXPECTED EARNINGS ANALYSIS YOU USED IS NOT A REASONABLE METHOD FOR ESTIMATING A FAIR ROE FOR LGE/KU.[142] DO YOU AGREE?

A97. No. As I discuss in my direct testimony,[143] expected earned rates of return for other utilities provide another useful benchmark of reasonableness. I noted earlier that the expected earnings approach is predicated on the comparable earnings test,

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[140] Maryland Public Service Commission, Case No. 9655, *Direct Testimony and Exhibits of Drew M. McAuliffe* (Mar. 3, 2021) at 19.
[141] Walters Direct at 62.
[142] *Id.* at 77-78.
[143] McKenzie Direct at 64-66.

which developed as a direct result of the Supreme Court decisions in *Bluefield*[144] and *Hope*.[145] As S&P recently observed, "Historically, there have been two approaches in calculating ROE in regulatory proceedings, a comparable earnings approach and a market analysis. In a comparable earnings approach, similar investments with similar risks are analyzed to determine an appropriate ROE."[146]

Q98. DOES THE INVESTMENT COMMUNITY REFERENCE EARNED RETURNS ON BOOK VALUE IN THEIR EVALUATION OF ELECTRIC UTILITIES?

A98. Yes. Book value accounting measures, including earned and expected returns on book equity, are instrumental to the financial analysis underpinning investors' evaluation of electric utilities, including credit ratings. S&P cited the relevance of earned returns on book value in highlighting the primary credit considerations in the utility industry, noting that "required rate of return on equity investment is closely linked to a utility company's profitability."[147] S&P indicated that "[f]or regulated utilities subject to full cost-of-service regulation and return-on-investment requirements, we normally measure profitability using ROE, the ratio of net income available for common stockholders to average common equity."[148] While recognizing that "the regulator ultimately bases its decision on an authorized ROE," S&P observed that "different factors such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of-service-based utilities centers on the utility's ability to consistently earn the authorized ROE."[149] In S&P's view,

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144 *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923), ("Bluefield").
145 *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), ("Hope").
146 S&P Global Market Intelligence, *The rate case process: establishing a fair return for regulated utilities*, RRA Regulatory Focus (Jun. 29, 2020).
147 Standard & Poor's Corporation, *Utilities: Key Credit Factors For The Regulated Utilities Industry,* Criteria Corporates (Nov. 19, 2013).
148 *Id.*
149 *Id.*

the earned return on book value may provide better insight into the financial health of the utility because it reflects the actual impact of regulation, not the theoretical outcome implied by an authorized ROE. Consistent with this paradigm, S&P recently examined trends in utility returns on book equity, as compared with authorized ROEs, in evaluating financial performance for the electric utility industry.[150] Similarly, in a review of financial quality measures for utilities, S&P noted that "[t]he earned return on equity . . . is one of the most widely followed measures of the industry's financial performance."[151]

Moody's also supports the relevance of returns on book value in its assessment of a utility's prospects. While noting that "[t]he authorized ROE is a popular focal point in many regulatory rate case proceedings," Moody's recognized that "earned ROEs, as reported by utilities and adjusted by Moody's," are a key gauge of financial performance.[152] As Moody's concluded, "[U]tilities are closer to earning their authorized equity returns, which is positive from an equity market valuation perspective."[153] In explaining its scorecard analysis for a Baa-rated utility, Moody's Investors' Service noted that regulatory outcomes should be "sufficient to attract capital without difficulty," and that this "will translate to returns (measured in relation to equity, total assets, rate base, or regulatory asset value, as applicable) that are average relative to global peers."[154]

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[150] S&P Global Ratings, *Utility-earned ROEs exceeded authorized since 2016, but 2019 may not match 2018*, Financial Focus (Jun. 10, 2019).
[151] S&P Global Market Intelligence, *Utility operating company financials mixed: ROE slips*, Financial Focus (Dec. 11, 2019).
[152] Moody's Investors Service, *Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles*, Sector In-Depth (Mar. 10, 2015).
[153] *Id*.
[154] Moody's Investors Service, *Regulated Electric and Gas Utilities,* Rating Methodology (Jun. 23, 2017).

Q99. WHAT OTHER EVIDENCE SUPPORTS A FINDING THAT RETURNS ON BOOK VALUE INFLUENCE INVESTORS' VALUATION DECISIONS?

A99. In addition to the materials cited above, a research paper by Dr. Aswath Damodaran emphasized the importance of considering returns on book value in evaluating performance and alternative investments.[155] Contradicting Mr. Walters' view that returns on book value are unrelated to an evaluation of investors' expected return on investment, Dr. Damodaran noted that "[w]hile returns on equity and capital are based upon accounting earnings and capital, and are designed to measure the quality of a firm's existing investments, they are correlated with returns you would make investing in the publicly traded equity of the firm."[156] A number of other peer-reviewed research studies also confirm the relationship between accounting-based performance measures and market-based measures such as stock returns.[157]

As Dr. Damodaran stated, "[W]e can safely conclude that the key number in a valuation is not the cost of capital that we assign a firm but the return earned on capital that we attribute to it."[158] This is exactly what the Expected Earnings method seeks to measure. If the allowed ROE is insufficient to provide a return on the book value of a utility's investment as compared with what investors expect other utilities of comparable risk to earn, the utility's ability to compete for capital

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[155] Aswath Damodaran, *Return on Capital (ROC), Return on Invested Capital (ROIC) and Return on Equity (ROE): Measurement and Implications*, New York University, Stern School of Business (July 2007).

[156] Damodaran, *supra* n.151 at 49.

[157] *See, e.g.,* Kenneth Lehn, Anil Makhija, *EVA, Accounting Profits, and CEO Turnover: An Empirical Examination, 1985-1994,* Journal of Applied Corporate Finance, Vol 10.2 (Summer 1997) at 90 (documenting a significant, positive correlation between ROE, market-based performance measures, and CEO turnover); D. Craig Nichols, James M. Wahlen, *How Do Earnings Numbers Relate to Stock Returns? A Review of Classic Accounting Research with Updated Evidence*, Accounting Horizons, Vol 18, No. 4 (Dec. 2004) at 272–274, 285 (documenting a significant positive relationship between stock returns and accounting earnings).

[158] Damodaran, *supra* n.151 at 6.

will be undermined. The Expected Earnings approach provides a measure of this necessary return as one component of the evaluation of a just and reasonable ROE.

Q100. WHAT IS MR. WALTERS' POSITION WITH RESPECT TO LGE/KU'S REQUESTED CAPITAL STRUCTURE?

A100. DOD accepts the Companies' proposed capital structures for purposes of computing an overall rate of return.[159] However, Mr. Walters also opines that the equity ratios requested by LGE/KU are "significantly higher" than both the average for his proxy group and the "typical" common equity ratio authorized for other utilities.[160] Mr. Walters notes that while he did not make an explicit adjustment to his ROE recommendation attributable to LGE/KU's requested capitalization, he states that "I have taken it into consideration in developing my recommended range and return."[161]

Q101. DO YOU AGREE WITH MR. WALTERS THAT LGE/KU'S REQUESTED CAPITAL STRUCTURES DISTINGUISH THE COMPANIES' OVERALL RISKS FROM OTHERS IN THE UTILITY INDUSTRY?

A101. No. As I noted in my direct testimony,[162] the Companies' common equity ratios fall within the range for my proxy utilities and are essentially identical to the average for the group of electric utility operating companies owned by these firms, with 22 of the 49 operating companies having equity ratios equal to or greater than the common equity ratio of approximately 53.1% requested by LGE/KU.[163]

Q102. IS THIS CONCLUSION CONFIRMED BY REFERENCE TO RECENT FINDINGS IN OTHER REGULATORY PROCEEDINGS?

A102. Yes. The table below presents the common equity ratios approved for electric utilities over the past eight quarters, as reported by RRA Regulatory Focus:

[159] *See* Exhibit CCW-1.
[160] Walters Direct at 25.
[161] Walters Direct at 25.
[162] McKenzie Direct at 77-80.
[163] Exhibit No. 12, pages 2-3.

TABLE R-4
ELECTRIC UTILITY ALLOWED COMMON EQUITY RATIOS

	Low		High	Average
Q1-19	48.00%	--	52.82%	50.86%
Q2-19	51.37%	--	57.02%	53.11%
Q3-19	49.46%	--	53.49%	51.41%
Q4-19	47.97%	--	56.00%	51.37%
Q1-20	42.50%	--	55.61%	50.07%
Q2-20	48.23%	--	54.77%	51.63%
Q3-20	46.00%	--	56.83%	51.33%
Q4-20	48.00%	--	56.83%	51.50%
Average	47.69%	--	55.42%	51.41%

Source: S&P Global Market Intelligence, *Major Rate Case Decisions*, RRA Regulatory Focus (Jan. 31, 2020, Feb. 2, 2021). Excludes capital structures that included cost-free items or tax credit balances.

As demonstrated in table above, the 53.1% common equity ratio requested by LGE/KU falls well within the range of capital structures approved for other electric utilities.

Q103. WHAT OTHER CONSIDERATIONS CONTRADICT MR. WALTERS' SUGGESTION THAT LGE/KU'S COMMON EQUITY RATIOS WARRANT A LOWER ROE?

A103. Mr. Walters' focus on capital structure, and the relative risk associated with debt leverage, ignores the fact that this is only one facet of a company's overall investment risk. The just and reasonable ROE is not evaluated in a vacuum; it is predicated on analyses for a group of comparable risk utilities, with the relative reliance on equity financing being only one factor considered in this overall assessment. As discussed in my direct testimony, utilities must maintain financial strength and liquidity to ensure adequate access to capital even during times of market volatility and stress. As a result, there is no basis for Mr. Walters' to suggest that a downward adjustment to the ROE might be warranted based only on variations in equity ratios between individual utilities.

IV. RESPONSE TO MS. PERRY AND MR. OWEN

Q104. DO MS. PERRY OR MR. OWEN CONDUCT AN INDEPENDENT EVALUATION OF A FAIR ROE FOR LGE/KU?

A104. No. Neither of these witnesses conducts any analysis of the cost of equity. Their testimony largely consists of citations to the U.S. Supreme Court's decisions in *Bluefield* and *Hope*, as well as presentation of selected data concerning previously authorized ROEs. Based on this limited review, Ms. Perry and Mr. Owen express their concern about the reasonableness of the Companies' proposed ROE.[164]

Q105. DO YOU AGREE WITH MR. OWEN THAT ALLOWED ROES PROVIDE ONE BENCHMARK WORTHY OF CONSIDERATION IN THE COMMISSION'S EVALUATION?

A105. Yes, I do. Importantly, however, such comparisons of allowed ROEs are only one consideration. While this data can be useful in the Commission's deliberations, it is not a substitute for the detailed analyses presented in my direct testimony.

Q106. DOES THE DATA PRESENTED BY MS. PERRY AND MR. OWEN CONFIRM YOUR CONCLUSION THAT THE ROE RECOMMENDATIONS OF MR. BAUDINO AND MR. WALTERS ARE TOO LOW?

A106. Yes. Ms. Perry cites an average allowed ROE for vertically integrated utilities from 2017 to present of 9.69%, and both witnesses note that the average ROE for vertically integrated utilities averaged 9.55% in 2020.[165] This confirms my earlier conclusion that the 9.00% and 9.30% ROE recommendation of AG/KIUC and DOD fall well below returns authorized for other utilities and are insufficient to meet the requirements of regulatory standards.

[164] Perry Direct at 7; Owen Direct at 28-36.
[165] Perry Direct at 11; Owen Direct at 31.

Q107. FROM YOUR POSITION AS A REGULATORY FINANCIAL ANALYST, WHAT DO YOU MAKE OF MS. PERRY'S AND MR. OWEN'S ADMONITION TO CONSIDER CUSTOMER IMPACTS WHEN ESTABLISHING A FAIR ROE?

A107. It is important to note that the determination of the ROE is made by investors in the capital markets and is not predicated on any notion of costs or savings to customers. The cost of attracting and retaining equity capital is a function of investor requirements, and while regulatory standards involve a balancing of the interests of customers and investors, ratepayer savings are not determinative when establishing the ROE. Ms. Perry's and Mr. Owen's suggestion that reducing ROE is inherently beneficial to customers ignores the negative impact that would ultimately result from an inadequate ROE. While a downward-biased ROE may provide the illusion of customer "savings" in the form of a lower revenue requirement in the short-term, the long-term impact of an inadequate ROE can be injurious to customers and the Kentucky economy.

As discussed earlier, there is a very real connection between the ROE and the availability of capital, and Mr. Owen ignores the negative impact that an inadequate ROE would have on investment. The ROE is the primary signal to investors, not only with respect to attracting new capital investment, but also in supporting existing utility operations. If the utility is unable to offer a competitive ROE, existing shareholders will suffer a capital loss as investors take advantage of other, more favorable opportunities, and the utility's stock price would fall. Moreover, as investors' confidence is undermined, the ability of utilities to access equity capital markets and expand investment will suffer. While the Companies would undoubtedly continue to meet their service obligations to customers, a downward-biased ROE would send an unmistakable signal to the investment community as they consider whether to commit capital in Kentucky, and at what cost.

Q108. MR. OWEN CONTENDS THAT "THE COVID-19 PANDEMIC IS NOT FACTORED INTO [YOUR] ANALYSIS."[166] IS THIS ACCURATE?

A108. No. My direct testimony contains extensive discussion of the implications of the COVID-19 pandemic for the economy and financial markets, and the underlying data supporting my analyses (*e.g.*, current beta values) reflect the impact of these events.

Q109. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A109. Yes, it does.

[166] Owen Direct at 35.

VERIFICATION

STATE OF TEXAS)
)
COUNTY OF TRAVIS)

The undersigned, **Adrien M. McKenzie**, being duly sworn, deposes and states that he is a President of FINCAP, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Adrien M. McKenzie

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 7th day of April 2021.

(SEAL)
Notary Public

Notary Public ID No. 131906507

My Commission Expires:
2/25/2023

NOTARY PUBLIC STATE OF TEXAS
BRUCE H FAIRCHILD
Notary ID #131906507
My Commission Expires
February 25, 2023

STATE ALLOWED ROEs

BAUDINO PROXY GROUP

	Company		(a) **Allowed ROE**	
1	ALLETE		9.25%	
2	Alliant Energy		10.00%	
3	Ameren Corp.		8.70%	
4	Avista Corp.		9.43%	
5	Black Hills Corp.		9.37%	
6	CMS Energy Corp.		9.90%	
7	Consolidated Edison		8.90%	
8	Duke Energy Corp.		9.90%	
9	Entergy Corp.		9.95%	
10	Eversource Energy		9.52%	
11	NorthWestern Corp.		10.03%	
12	Pub Sv Enterprise Grp.		9.60%	
13	Sempra Energy		10.20%	
14	Southern Company		12.50%	
15	WEC Energy Group		9.70%	
16	Xcel Energy Inc.		9.60%	
	Range	**8.70%**	**--**	**12.50%**
	Average		**9.78%**	
	Midpoint		**10.60%**	

(a) The Value Line Investment Survey (Jan. 22, Feb. 12 and Mar. 12, 2021).

WALTERS PROXY GROUP

	Company		(a) Allowed ROE	
1	ALLETE		9.25%	
2	Alliant Energy		10.00%	
3	Ameren Corp.		8.70%	
4	Avangrid, Inc.		8.78%	
5	Avista Corp.		9.43%	
6	Black Hills Corp.		9.37%	
7	CMS Energy Corp.		9.90%	
8	Consolidated Edison		8.90%	
9	DTE Energy Co.		9.90%	
10	Duke Energy Corp.		9.90%	
11	Entergy Corp.		9.95%	
12	Eversource Energy		9.52%	
13	NorthWestern Corp.		10.03%	
14	Pub Sv Enterprise Grp.		9.60%	
15	Sempra Energy		10.20%	
16	Southern Company		12.50%	
17	WEC Energy Group		9.70%	
18	Xcel Energy Inc.		9.60%	
	Range	**8.70%**	**--**	**12.50%**
	Average		**9.73%**	
	Midpoint		**10.60%**	

(a) The Value Line Investment Survey (Jan. 22, Feb. 12 and Mar. 12, 2021).

BAUDINO PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	9.0%	1.0161	9.1%
2	Alliant Energy	10.5%	1.0250	10.8%
3	Ameren Corp.	10.0%	1.0397	10.4%
4	Avista Corp.	8.0%	1.0192	8.2%
5	Black Hills Corp.	8.5%	1.0282	8.7%
6	CMS Energy Corp.	14.0%	1.0429	14.6%
7	Consolidated Edison	8.0%	1.0219	8.2%
8	Duke Energy Corp.	8.5%	1.0135	8.6%
9	Entergy Corp.	11.0%	1.0276	11.3%
10	Eversource Energy	9.5%	1.0263	9.7%
11	NorthWestern Corp.	9.0%	1.0176	9.2%
12	Pub Sv Enterprise Grp.	11.0%	1.0260	11.3%
13	Sempra Energy	11.0%	1.0461	11.5%
14	Southern Company	13.0%	1.0213	13.3%
15	WEC Energy Group	13.0%	1.0196	13.3%
16	Xcel Energy Inc.	10.5%	1.0332	10.8%
	Average			**10.6%**
	Midpoint			**11.4%**

(a) The Value Line Investment Survey (Jan. 22, Feb. 12 and Mar. 12, 2021).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) (a) x (b).

WALTERS PROXY GROUP

		(a)	(b)	(c)
	Company	**Expected Return on Common Equity**	**Adjustment Factor**	**Adjusted Return on Common Equity**
1	ALLETE	9.0%	1.0161	9.1%
2	Alliant Energy	10.5%	1.0250	10.8%
3	Ameren Corp.	10.0%	1.0397	10.4%
4	Avangrid, Inc.	5.5%	1.0066	5.5%
5	Avista Corp.	8.0%	1.0192	8.2%
6	Black Hills Corp.	8.5%	1.0282	8.7%
7	CMS Energy Corp.	14.0%	1.0429	14.6%
8	Consolidated Edison	8.0%	1.0219	8.2%
9	DTE Energy Co.	11.0%	1.0312	11.3%
10	Duke Energy Corp.	8.5%	1.0135	8.6%
11	Entergy Corp.	11.0%	1.0276	11.3%
12	Eversource Energy	9.5%	1.0263	9.7%
13	NorthWestern Corp.	9.0%	1.0176	9.2%
14	Pub Sv Enterprise Grp.	11.0%	1.0260	11.3%
15	Sempra Energy	11.0%	1.0461	11.5%
16	Southern Company	13.0%	1.0213	13.3%
17	WEC Energy Group	13.0%	1.0196	13.3%
18	Xcel Energy Inc.	10.5%	1.0332	10.8%
	Average			**10.3%**
	Midpoint			**10.1%**

(a) The Value Line Investment Survey (Jan. 22, Feb. 12 and Mar. 12, 2021).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) (a) x (b).

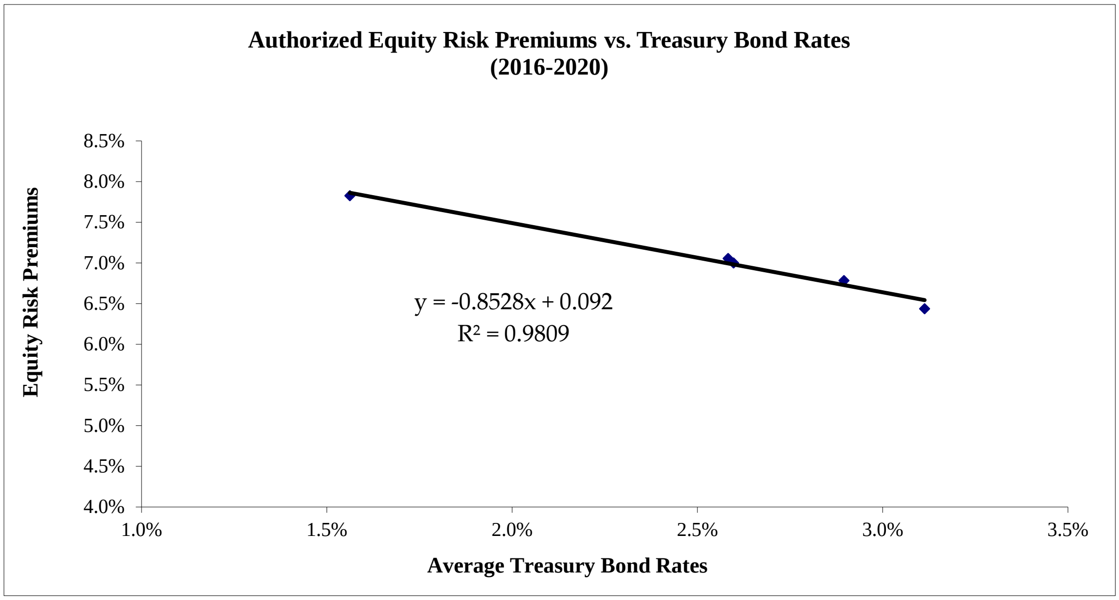
	Treasury	**A-rated Utility**	**Baa-rated Utility**
Adjusted Equity Risk Premium			
(a) Avg. Yield over Study Period	2.55%	3.80%	3.80%
(b) Projected Bond Yield	2.10%	3.25%	3.25%
Change in Bond Yield	-0.45%	-0.55%	-0.55%
(c) Risk Premium/Interest Rate Relationship	-0.8528	-0.8180	-0.8180
Adjustment to Average Risk Premium	0.38%	0.45%	0.45%
(a) Average Risk Premium over Study Period	7.02%	5.77%	5.77%
Adjusted Risk Premium	**7.41%**	**6.22%**	**6.22%**
Implied Cost of Equity			
(b) Projected Bond Yield	2.10%	3.25%	3.54%
Adjusted Equity Risk Premium	7.41%	6.22%	6.22%
Risk Premium Cost of Equity	**9.51%**	**9.47%**	**9.76%**

(a) Study Period is 2016-2020 (Walters Direct at 46, lines 1-3).
Average yields and risk premiums from Exhibit CCW-12 (Treasury), Exhibit CCW-13 (A-rated Utility), and Exhibit CCW-14 (Baa-rated Utility) for the period 2016-2020.

(b) Projected Treasury bond yield (Walters Direct at 46, lines 5-6).
Projected A-rated utility bond yield equal to projected Treasury bond yield plus 13-week average A-rated utility yield spread (Exhibit CCW-15, p. 1): 2.10% + 1.15% =3.25%
Projected Baa-rated utility bond yield equal to projected Treasury bond yield plus 13-week average Baa-rated utility yield spread (Exhibit CCW-15, p. 1): 2.10% + 1.44% =3.54%

(c) Based on regression of equity risk premiums and interest rates for the period 2016-2020 as shown on pages 2-3 of this exhibit.

REGRESSION RESULTS (TREASURY BOND)



SUMMARY OUTPUT

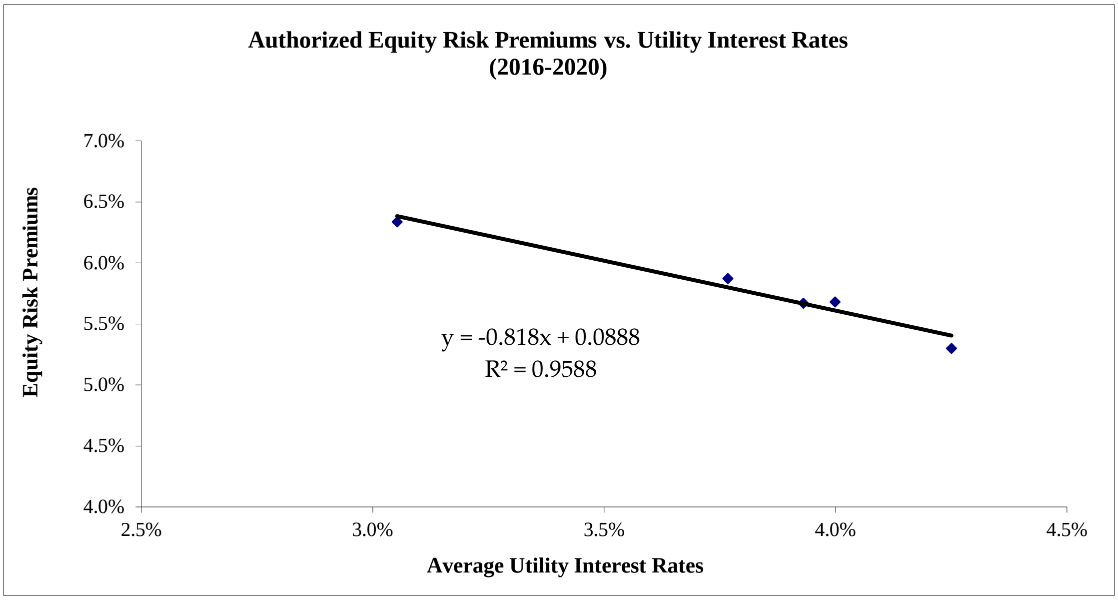
Regression Statistics	
Multiple R	0.990413569
R Square	0.980919037
Adjusted R Square	0.974558716
Standard Error	0.000817064
Observations	5

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.00010296	0.00010296	154.2247677	0.001125107
Residual	3	2.00278E-06	6.67594E-07		
Total	4	0.000104962			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.091967848	0.001788798	51.41320223	1.62052E-05	0.086275093	0.097660602	0.086275093	0.097660602
X Variable 1	-0.85284716	0.068674285	-12.41872649	0.001125107	-1.071399388	-0.634294939	-1.071399388	-0.634294939

REGRESSION RESULTS (A-RATED UTILITY)



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.979173106
R Square	0.958779971
Adjusted R Square	0.945039962
Standard Error	0.000886186
Observations	5

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5.48002E-05	5.48002E-05	69.78015309	0.003596741
Residual	3	2.35598E-06	7.85326E-07		
Total	4	5.71561E-05			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.088805134	0.003742066	23.73158006	0.000163954	0.076896211	0.100714058	0.076896211	0.100714058
X Variable 1	-0.81802136	0.097926151	-8.353451568	0.003596741	-1.129666075	-0.506376641	-1.129666075	-0.506376641

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	**CASE NO. 2020-00349**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	**CASE NO. 2020-00350**

REBUTTAL TESTIMONY OF
CHRISTOPHER M. GARRETT
CONTROLLER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: April 12, 2021

TABLE OF CONTENTS

Q. Please state your name, position, and business address.

A. My name is Christopher M. Garrett. I am the Controller for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") and an employee of LG&E and KU Services Company, which provides services to LG&E and KU (collectively, the "Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What are the purposes of your testimony?

A. The purposes of my rebuttal testimony are to rebut intervenor testimony on the issues of (1) the Companies' method of valuation; (2); pension assets and liabilities; (3) certain cash working capital adjustments; (4) excess accumulated deferred income tax issues relating to Mr. Kollen's proposed adjustments; (5) removal of construction work in progress ("CWIP") and capitalization of construction financing costs using an allowance for funds used during construction ("AFUDC"); and (6) generator outage expense normalization and deferral accounting.

I. USE OF CAPITALIZATION AS A METHOD OF VALUATION

Q. Do any intervenors argue that the Companies' use of capitalization as a method of valuating the Companies' property is inappropriate?

A. Yes. Mr. Kollen argues the Commission should use rate base in calculating the return on component of the base revenue requirement.[1] He asserts that rate base is superior to capitalization because it is more precise and accurate, allows the Commission to specifically review, assess, and quantify each of the costs that will earn a return, and avoids the need to reconcile capitalization to rate base as a reasonableness test.[2]

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[1] Direct Testimony and Exhibits of Lane Kollen at 40.
[2] Direct Testimony and Exhibits of Lane Kollen at 37-38.

Q. Do the Companies agree with Mr. Kollen's argument that rate base is the superior valuation methodology?

A. No. Capitalization appropriately and accurately reflects the extent to which the Companies fund their utility operations. It is also more straightforward and eliminates the need for theoretical arguments and adjustments to rate base for non-cash and other items such as those called for by Mr. Kollen. Additionally, the Companies' capitalization methodology is consistent with the overall balance sheet approach for evaluating cash working capital in a revenue requirement calculation as discussed in the Rate Case and Audit Manual prepared by NARUC Staff Subcommittee of Accounting and Finance (Summer 2003).[3] Finally, if rate base is adjusted appropriately, there should be no material difference between rate base and capitalization.

Q. Has this Commission agreed with the Companies that capitalization is the better valuation methodology for the Companies?

A. Yes. The Commission has chosen capitalization as the appropriate valuation methodology for LG&E and KU for decades. In LG&E's Case No. 2000-00080, the Commission specifically recognized that capitalization is "a better measure of the real cost of providing service since it is the cost of debt and equity that is reflected in the financial statements of the utility."[4]

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[3] Rate Case and Audit Manual Prepared by NARUC Staff, Subcommittee on Accounting and Finance (2003), available at: https://ipu.msu.edu/wp-content/uploads/2017/09/NARUC-Ratecase-and-Audit-Manual-2003.pdf.

[4] *The Application of Louisville Gas & Electric Company to Adjust Its Gas Rates and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks*, Case No. 2000-00080, Order at 11 (Ky. PSC Sept. 27, 2000).

Q. Is Mr. Kollen's argument that the Commission now uses rate base for all large investor-owned utilities subject to its ratemaking jurisdiction a justification for changing this policy after decades of use?

A. No. The fact that other investor-owned utilities use rate base in no way mandates the Commission must select the rate base methodology for the Companies in these cases. These other investor-owned utilities operate in multiple jurisdictions that use rate base; their Kentucky jurisdictional operations typically are among the smallest regulated operations within their respective holding company systems. In contrast, the primary if not exclusive regulatory jurisdiction for the Companies is Kentucky. Each of the two other investor-owned electric utilities which have proposed or have been required to use the rate base method of valuation in Kentucky also operate in multiple jurisdictions where rate base is used.[5]

As discussed in my Direct Testimony, the Companies have used the capitalization valuation methodology for more than 40 years.[6] The Companies' historic use of capitalization is especially important as KRS 278.290 and Commission

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[5] KY Power is a subsidiary of American Electric Power ("AEP"), which also operates in Texas, Michigan, Arkansas, Louisiana, and Ohio, among other states, and uses the rate base methodology. Tex Utilities Code 36.003; *Cities for Fair Util. Rates v. PUC, 924 S.W.2d 933, 1996 Tex. LEXIS 88 (Tex. 1996)*; *Application of Indiana Michigan Power Company for Authority to Increase Its Rates for the Sale of Electric Energy and for Approval of Depreciation Accrual Rates and Other Related Matters,* Case No. U-18370, Order at 86 (MI PSC Apr. 12, 2018); *Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs*, Docket No. 19-008-U, Order No. 12 (AR PSC Dec. 20, 2019); *Entergy Gulf States, Inc. v. Louisiana PSC*, 730 So. 2d 890 (LA. S.Ct. 1999); *Babbit v. Public Utilities Com.*, 391 N.E.2d 1376 (Ohio 1979).
Duke Kentucky is a subsidiary of Duke Energy, which also operates in Indiana, North Carolina, and South Carolina, among other states, and uses the rate base methodology. *Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code 8-1-2-42.7 and 8-1-2-61, for (1) Authority to Modify Its Rates and Charges for Electric Utility Service Through a Step-In of New Rates and Charges Using a Forecasted Test Period* [], Cause No. 45253, Order (IN URC June 29, 2020); *Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Docket No. E-7, Sub 1214, Order (NC UC Mar. 31, 2021); *Hamm v. South Carolina Public Service Com.*, 364 S.E.2d 455, 456 (S.C. 1988)("The PSC's authority to determine rate base is set forth in Section 58-27-180, S. C. Code Ann. (1976)").
[6] Direct Testimony of Christopher M. Garrett at 4.

precedent require the Commission to give due consideration to a utility's historic method of property valuation when fixing the value of property. The Commission has stated that it "will consider using an approach different from that previously used"[7] only if a justification exists. The use of rate base by other investor-owned utilities is not sufficient justification to support an abrupt departure from the valuation methodology used by the Companies for many decades. The valuation of a utility's property in connection with setting rates is necessarily a stand-alone analysis. Like the Companies' long-standing use of CWIP for ratemaking purposes,[8] capitalization is a long-standing policy of this Commission for the Companies.

Q. In addition to the long-standing precedent for the Companies' use of capitalization, are there other reasons why the Companies view capitalization as a better measure of the value of their property than rate base?

A. Yes. There are numerous reasons. First, capitalization is simpler and more transparent. Second, rate base improperly excludes certain assets and liabilities, which deny the Companies the ability to recover their cost of capital, thereby increasing regulatory lag and financing risk. Third, there is a current mismatch for accumulated deferred income taxes ("ADIT") in rate base, which does not exist in capitalization. Fourth, the Companies' nonregulated activities are de minimus, which negates the concern that a portion of the Companies' capitalization has been used to finance non-regulated activities and capital allocations from the Companies' parent, LG&E and KU Energy,

[7] Case No. 2000-00080, Order at 7 (Ky. PSC Sept. 27, 2000).
[8] *Jefferson County Fiscal Court v. Kentucky Public Service Commission*, Opinion and Order, 29 PUR 4th, pp. 143-144 (Franklin Circuit Court March 15, 1977) ("The commission was on sound ground when it allowed LG&E to include CWIP in the rate base. The evidence is uncontradicted that, for many years, LG&E (with commission approval) has included CWIP in its rate base, but it has not increased its earnings by an allowance for funds used during construction (AFUDC)").

are not in excess of that needed to finance its utility operations. Fifth, there are no differences between capitalization and rate base for timing differences related to the Companies' financings. Lastly, the Companies' reconciliation of rate base and capitalization provides validation of reasonableness of the Companies' lead-lag study.

Q. Why is capitalization a simpler and more transparent valuation methodology as compared to rate base?

A. The rate base valuation methodology, including the performance of a theoretical lead-lag study, requires a significant amount of judgment in determining the appropriate rate base valuation. This is evidenced by Mr. Kollen's recommendation of multiple rate base adjustments, which are also contested by the Companies and discussed below. The capitalization valuation methodology is simpler and more transparent because all balance sheet amounts are included, with limited judgment required. The use of rate base is less precise and less accurate as the lead-lag study component of rate base is an estimate, whereas capitalization determines the true cost of capital based on amounts reflected on the balance sheet. In short, rate base offers the opportunity for greater argument and contention; capitalization is far more straightforward and less susceptible to debate.

Q. What assets and liabilities are improperly excluded from rate base in this case?

A. As the reconciliation between capitalization and rate base demonstrates, one of the primary differences between rate base and capitalization results from the exclusion from rate base of certain regulatory assets and liabilities established *in connection with providing utility service*. These regulatory assets and liabilities are appropriately included in capitalization[9] as they involve capital outlays for prudent utility operating costs such as generator outage expense and storm costs, which have lengthy amortization periods. The exclusion of these items from rate base results in the Companies not recovering their associated carrying costs for lengthy periods, i.e. 8 years for outages and 10 years for storms. This issue merits the Commission's attention and further emphasizes why the Commission should allow for the Companies' continued use of capitalization.

Q. What amount of carrying costs will the Companies be denied under Mr. Kollen's rate base proposal?

A. Table 1 as shown below demonstrates how the Companies would under-recover their cost of capital by $36.0 million (KU $18.6 million; LG&E Electric $11.7 million; and LG&E Gas $5.7 million) if Mr. Kollen's proposal is accepted.

Table 1

AG and KIUC Rate Base Issues	KU	LG&E Electric	LG&E Gas
Utilize Rate Base Instead of Capitalization to Reflect Return On Component for Base Rates(1)	(3.596)	0.928	(0.356)
Modify CWC to Exclude Non-Cash Amounts(2)	(4.592)	(3.267)	(0.531)
Exclude Non-Cash Pension and OPEB Related Asset and Liability Amounts(3)	(7.021)	(7.460)	(3.956)
Exclude All Account 184 Pension Clearing Account Amounts(4)	(0.498)	(0.563)	(0.255)
Reduce Account 186 to Correct Company Error in Projected Balances(5)	-	-	-
Remove 95% of Corrected Account 186 Balance to Reflect as CWIP(2)	(1.128)	(0.458)	-
Reduce CWIP by the Amount of Vendor Financing in Accounts Payable(2)	(1.720)	(0.865)	(0.644)
	(18.556)	**(11.686)**	**(5.740)**

(1) Rebuttal Exhibit CMG-1 which includes updates for the Companies supplemental responses to PSC 1-56 filed on 2/26/2021. KU ($39.866M) * 9.02 KU Pretax WACC = ($3.596M); LG&E Electric $10.343M * 8.97% LG&E Pretax WACC = $0.928M; LG&E Gas ($3.966M) * 8.97% LG&E Pretax WACC = ($0.356M).
(2) Direct Testimony and Exhibits of Lane Kollen at 7.
(3) KU and LG&E Electric: Direct Testimony and Exhibits of Lane Kollen at 7. LG&E Gas: Supplemental Response to PSC 1-56 filed on 2/26/2021 Schedule B-5.2 F ($58.754M) * (1-24.95% Eff Tax Rate) * 8.97% LG&E Pretax WACC = ($3.956M).
Prepaid Pension $19.010M + Regulatory Asset FAS 158 $54.439M + Postretirement Liability ($14.695M) = $58.754M
(4) KU and LG&E Electric: Direct Testimony and Exhibits of Lane Kollen at 7 for KU and LG&E Electric. LG&E Gas: Supplemental Response to PSC 1-56 filed on 2/26/2021 Schedule B-5.2 F ($2.841M) * 8.97% LGE Pretax WACC = ($0.255M).
(5) Error corrected in the Companies supplemental responses to PSC 1-56 filed on 2/26/2021: Correction is incorporated into the first adjustment in the table.

Q. Briefly describe the mismatch that currently exists for ADIT in rate base but not in capitalization.

[9] *See* Rebuttal Exhibit CMG-1: Regulatory assets and liabilities excluded from rate base: KU $33.6 million; LG&E Electric $15.7 million; and LG&E Gas $4.5 million.

A. The ADIT associated with the regulatory assets and liabilities excluded from rate base discussed above has not been excluded, or was not proposed to be excluded, from rate base, resulting in an improper mismatch in the tax treatment and the underlying asset and liability treatment. Regardless of whether the Commission decides regulatory assets should or should not be included in rate base, the ADIT treatment should be consistent with the underlying regulatory asset and liability treatment to avoid the current mismatch. This mismatch does not exist in capitalization because all assets and liabilities are included in the capitalization valuation.

Q. Are there any concerns that the Companies' non-regulated activities are causing its capitalization to be overstated?

A. None. As discussed in my Direct Testimony, while rate base and capitalization theoretically should be equal, it is rare that this happens.[10] When a utility's capitalization exceeds rate base, it raises concerns that a portion of the capitalization has been used to finance non-regulated activities.[11] For the Companies, though, that is not the case. This fact is confirmed by the Companies' recent nonregulated operations annual filings submitted to the Commission on March 31, 2021.[12]

Q. Are capital allocations from the Companies' parent company in excess of that needed to finance the Companies' direct investment rate base?

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[10] *Application of Louisville Gas and Electric Company for Approval of an Alternative Method of Regulation of its Rate and Service*, Case No. 1998-00426, Order at 3 (Ky. PSC June 1, 2000).
[11] Case No. 2000-00080, Order at 5 (Ky. PSC Sept. 27, 2000).
[12] *See* Rebuttal Exhibit CMG-2: KU's Annual Report of Nonregulated Activities required by 807 KAR 5:080 for calendar year 2020 shows that KU's nonregulated activities make up only 0.00099% of total revenue. LG&E's Annual Report of Nonregulated Activities required by 807 KAR 5:080 for calendar year 2020 shows that LG&E's nonregulated activities make up only 0.20437% of total revenue.

A. No. This was an issue in the recent Kentucky Power case in which the Commission ordered Kentucky Power to use the rate base methodology rather than capitalization.[13] The Commission found that capitalization was not reasonable because it "measures the capital allocations to Kentucky Power from its parent company, in excess of that needed to finance Kentucky Power's direct investment rate base as determined herein."[14] Instead, the Commission stated rate base was a more accurate method of measuring Kentucky Power's financial health because it "measures the direct investment into Kentucky Power's system."[15] There is no evidence that the capital allocations from the Companies' parent company, LG&E and KU Energy LLC, are in excess of what is needed to finance the Companies' direct regulated utility operations as confirmed by its lack of nonregulated activities.

Q. Are capitalization and rate base different because of timing differences related to the Companies' financings?

A. No, the Companies fund expenditures with short-term debt until such time the short-term balances reach a level large enough to be cost-effectively replaced through long-term debt issuances; thus, the Companies rarely have excess cash.

Q. Does the Companies' reconciliation between rate base and capitalization provide the Commission with any other insights into the appropriateness of the Companies' valuation?

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[13] *Electronic Application of Kentucky Power Company for (1) A General Adjustment of Its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Public Convenience and Necessity; and (5) All Other Required Approvals and Relief*, Case No. 2020-00174, Order at 5 (Ky. PSC Jan. 13, 2021).
[14] *Id.*
[15] *Id.*

A. Yes, the reconciliation provides assurance to the Commission that the Companies' capitalization valuation is reasonable because a properly performed lead-lag study should result in a similar rate base and capitalization valuation. As demonstrated in Table 2 below, there is only a 0.34% on a total basis difference between rate base and capitalization valuations.[16] Additionally, the reconciliation shown in Table 2 confirms that rate base will not always result in a lower valuation than capitalization.

Table 2

	KU	LG&E Electric	LG&E Gas	Total
Capitalization	$ 5,233,287,234	$ 3,449,573,908	$ 1,081,738,329	$ 9,764,599,471
Rate Base	$ 5,193,420,778	$ 3,459,916,683	$ 1,077,772,771	$ 9,731,110,232
Difference	$ 39,866,455	$ (10,342,775)	$ 3,965,557	$ 33,489,239
% of Capitalization	0.76%	(0.30%)	0.37%	0.34%
% of Rate Base	0.77%	(0.30%)	0.37%	0.34%

Q. Do you agree with Mr. Kollen's assertion that the use of rate base avoids the need to reconcile rate base and capitalization?

A. No. KRS 278.290 requires the Commission to consider both capitalization and rate base in every case and determine which methodology to use based on the record. Furthermore, in connection with this valuation, the Commission by regulation has required the reconciliation be provided in the application. 807 KAR 5:001 Section 16(6)(f) states that in its application for a general rate adjustment, a utility "shall provide a reconciliation of the rate base and capital used to determine its revenue requirements."

[16] Amounts provided in the table are based on the Companies' errata filing on February 26, 2021, Supplemental Response to PSC 1-56.

Q. Do the Companies have any recommendations for the Commission should it decide to order the Companies to use the rate base methodology?

A. Yes. The calculations for the impact of the valuation methodology differences should be updated using Table 1 above which incorporates the corrections from the Companies' February 26, 2021 errata filing. Mr. Kollen's calculation fails to correct for all the issues identified in the Companies' errata filing.[17] Additionally, the Commission should make an adjustment to include all regulatory assets and liabilities established *in connection with providing utility service* in rate base to appropriately compensate both the Companies and customers for the deferrals.

Again, however, for the reasons previously stated, there is no justification for making such a radical change in property valuation methodologies in these cases.

II. PENSION ASSETS AND LIABILITIES

Q. Do any of the intervenors take exception to the Companies' inclusion of pension and OPEB related assets and liabilities in the calculation of its cost of service?

A. Yes. Mr. Kollen recommends that the Commission reject the Companies' request to include pension and OPEB related assets and liabilities in rate base via the Companies' cash working capital adjustment. Mr. Gorman takes issue with the Companies' inclusion of the prepaid pension asset in its rate base and argues that the Commission should remove the prepaid pension asset with no adjustment to operating expense.

Q. Please describe the intervenors' assertion for excluding the pension and OPEB related assets and liabilities from rate base?

[17] Companies' errata filing on February 26, 2021, Supplemental Response to PSC 1-56.

A. The primary argument appears to be centered around fundamental misunderstandings on whether these assets and liabilities represent non-cash items and whether there are applicable financing costs. Additionally, Mr. Kollen contends there is a fundamental difference in the Companies' accounting and Kentucky Power's accounting; however, there is not. Lastly, Mr. Gorman claims the Companies have fully recovered all contributions to the pension trust from customers; however, they have not.

Q. Can you present the Companies' position against these arguments?

A. Yes, the Companies' pension and OPEB related assets should be included in rate base and capitalization for several reasons. First, these assets and liabilities are cash financed and have been cash financed in a prudent manner. Second, the Companies' customers are receiving a net revenue requirement reduction from their inclusion. Third, despite Mr. Kollen's assertion, there is no fundamental difference in the accounting treatment between the Companies and Kentucky Power. There are simply differences in the presentation and recovery periods for ratemaking purposes. Fourth, at the request of Mr. Kollen and the intervenors in the 2014 rate case proceedings, the Companies agreed to amortize actuarial gains and losses for pensions over a 15-year period.[18] The Companies agreed to this treatment even though it defers pension costs beyond the period required by Generally Accepted Accounting Principles ("GAAP").[19] Thus, the Companies should be allowed to recover the associated carrying costs of

[18] *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2014-00371, Order at 4-5 (Ky. PSC June 30, 2015); *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2014-00372, Order at 5 (Ky. PSC June 30, 2015). *See also* pages 15-16 of this Rebuttal Testimony.

[19] Case No. 2014-00371, Order at 4-5 (Ky. PSC June 30, 2015); Case No. 2014-00372, Order at 5 (Ky. PSC June 30, 2015).

these deferrals. Lastly, the Companies have not fully recovered all contributions to the pension trust from customers, as asserted by Mr. Gorman.

Q. Do the Companies' pension and OPEB related assets and liabilities represent non-cash items?

A. No, they represent cash items. As shown in Rebuttal Exhibit CMG-3, the sum of the pension and OPEB related assets and liabilities represents the amount by which pension and OPEB contributions exceed net periodic pension and OPEB costs. The rollforwards provide evidence that the pension liability turned into a prepaid pension asset in 2019 largely as a result of the 2018 pension contributions. These 2018 contributions brought the Companies' allocations of the pension plans to a fully-funded status, which is consistent with the Commission's direction to eliminate underfunding expressed in the final orders in the Companies' 2003 base rate proceedings and sound pension management.[20] The Companies have also included the pension contribution disbursement requests since January 1, 2018 in Rebuttal Exhibit CMG-3. Lastly, the Companies further note that the reconciliation of capitalization and rate base (Rebuttal Exhibit CMG-1) includes no reconciling differences for pension and OPEB balances providing further proof that these items are cash financed.

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[20] *An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Louisville Gas and Electric Company,* Case No. 2003-00433, Order at 37, 78 (Ky. PSC June 30, 2004) ("The Commission does have concerns about the underfunded status of LG&E's pension and post-retirement plans. LG&E should develop and implement a plan that eliminates the underfunding within a reasonable time … In addition, LG&E should file progress reports describing the progress made in eliminating the underfunding of its pension and post-retirement plans."); *An Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company,* Case No. 2003-00434, Order at 33-34, 68 (Ky. PSC June 30, 2004) ("The Commission does have concerns about the underfunded status of KU's pension and post-retirement plans. KU should develop and implement a plan that eliminates the underfunding within a reasonable time … In addition, KU should file progress reports describing the progress made in eliminating the underfunding of its pension and post-retirement plans.").

Q. Are there applicable carrying costs associated with the pension and OPEB related assets and liabilities?

A. Yes. The *net* pension and OPEB related asset and liability is financed no differently than utility plant.

Q. Are customers compensated in any manner for the financing costs associated with pension and OPEB related assets and liabilities?

A. Yes. Customers are compensated for those financing costs in the form of reduced pension and OPEB expenses along with reduced income tax expense for the cash contributions in excess of net periodic pension and OPEB costs.

Q. Have the Companies calculated the overall benefit provided to customers by the inclusion of the Companies' pension and OPEB related assets and liabilities in rate base and capitalization?

A. Yes, as shown in Rebuttal Exhibit CMG-4, the inclusion of the pension and OPEB related assets and liabilities provides a net $4.7 million revenue requirement reduction for KU customers.[21] For LG&E, this net revenue requirement reduction is $11.9 million for electric customers and $2.1 million for gas customers per Rebuttal Exhibit CMG-5.[22] The benefits include not only the impact of lower pension expense from the 7.25% Expected Return on Assets ("EROA"), but also the reduction in pension expense due to the impact of the 7.25% EROA being applied to the avoided PBGC variable rate premiums. Additionally, the benefits from the deferred amortization of actuarial gains

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[21] The Companies have updated the attachment provided in response to AG-KIUC 2-11 to incorporate all pension and OPEB related assets and liabilities. To determine the amount by which pension and OPEB related assets and liabilities exceed the net periodic pension and OPEB costs, all accounts must be included because ASC 715, *Compensation – Retirement Benefits* requires the Companies to recognize the funded status of the plans resulting in offsetting entries to pension and OPEB related assets and liabilities.
Rebuttal Exhibit CMG-4 uses 7.25% EROA as discussed at page 12 of Mr. Arbough's Rebuttal Testimony.

[22] Rebuttal Exhibit CMG-5 uses 7.25% EROA as discussed at page 12 of Mr. Arbough's Rebuttal Testimony.

and losses have been added to the analysis. Mr. Kollen failed to acknowledge the benefits from this deferral in his proposed exclusion of the pension and OPEB related assets and liabilities. Lastly, the benefits include the impacts of excess ADIT. The Companies note that the excess ADIT benefits are large and make up a significant portion of the proposed Economic Relief Surcredit. The Companies were able to deduct the large pension contributions[23] that occurred in January 2018 on the 2017 tax return thus yielding a significant benefit for customers from the higher income tax rates that existed before passage of the Tax Cuts and Jobs Act in 2017. Mr. Kollen also failed to acknowledge the pension excess ADIT benefits in his proposal, which is discussed later in my rebuttal testimony.

Q. Do the Companies agree with Mr. Kollen's assertion that the amounts recorded by the Companies in Account 128 *Prepaid Pension* are different than the amounts recorded by Kentucky Power in Account 165 *Prepayments*?

A. No. In fact, the Companies accounting treatment for pensions and OPEB benefits is very similar to Kentucky Power's accounting treatment. The amount included by Kentucky Power in Account 165 *Prepayments* represents Kentucky Power's "**cumulative <u>cash</u> contributions** in excess of cumulative pension and OPEB cost."[24] Just like Kentucky Power, the sum of the amounts recorded in Account 128 *Prepaid Pension*, Account 182 *Regulatory Assets Pension and Postretirement*, Account 184 *Pension and OPEB Clearings*, Account 228 *Postretirement Liabilities*, and Account

[23] Pension contributions in January 2018 as shown on Rebuttal Exhibit CMG-3 are $46 million for KU and $54 million for LG&E.

[24] *See* Rebuttal Exhibit CMG-6: Case No. 2020-00174, Rebuttal Testimony of Heather M. Whitney at R6, Line No. 1: "The balances in 1650010 and 1650035 reflect the Companies' **cumulative <u>cash</u> contributions** in excess of cumulative pension and OPEB cost.".

254 *Regulatory Liabilities Postretirement* represents the Companies "**cumulative <u>cash</u> contributions** in excess of cumulative pension and OPEB cost."[25]

There are, however, two differences in the accounting treatment between Kentucky Power and the Companies which are discussed below.

Q. Please describe the two differences in the accounting treatment between Kentucky Power and the Companies mentioned above regarding their pension and OPEB benefits.

A. The first difference between the two is that, unlike Kentucky Power, the Companies did not make accounting entries for ratemaking purposes to reclassify the *net* pension and OPEB assets to *Prepayments*. The accounting reclassification entries were unnecessary for the Companies because the Companies included their pension and OPEB related assets and liabilities in cash working capital via the balance sheet analyses of the lead-lag studies. This was not the case for Kentucky Power because they did not file a lead-lag study. Kentucky Power instead made reclassification entries for ratemaking purposes to include its pension and OPEB related assets and liabilities in rate base via its reclassification entries to Account 1650010-1650035, *Prepayments*.[26]

The second difference relates to the amortization of actuarial gains and losses. As discussed in its response to AG-KIUC 2-13, the parties to the Settlement Agreement, Stipulation, and Recommendation ("Settlement") in the Companies' 2014 base rate

[25] *Id*.

[26] *See* Rebuttal Exhibit CMG-6: Case No. 2020-00174, Rebuttal Testimony of Heather M. Whitney at R10-12, 14. For Kentucky Power, the composition of Account 1650010/1650035 *Prepayments* represents the reclassification of Account 129 (Prepaid OPEB Asset), Account 228 (Pension Liability), Account 182 (Regulatory Asset), Account 190 (ADIT asset), and Account 219 (ASC – 715 Other Comprehensive Income) balances.

cases agreed that the Commission should approve regulatory asset treatment for the difference between (1) the Utilities' pension expense booked according to its accounting policy on record with the Securities and Exchange Commission and in accordance with GAAP and (2) pension expense with actuarial gains and losses amortized over 15 years.[27] The Commission accepted all provisions set forth in the Settlement. The Companies are currently amortizing the regulatory asset over the authorized 15-year period. Accordingly, the regulatory asset associated with this difference is included in rate base / capitalization along with the associated ADIT and excess deferred income taxes because customers are being provided the benefit of lower pension expense from the reduced amortization costs as shown in Rebuttal Exhibits CMG-4 and CMG-5. Denying the Companies the recovery of its carrying costs for this deferral, were no expense adjustment made, would be arbitrary and inconsistent.

Q. Do the Companies agree with Mr. Gorman's assertion that the Companies have fully recovered their contributions to the pension trust from customers?

A. No, Mr. Gorman's assertion implies that the Companies have over recovered their pension costs. However, his analysis only covers the periods since 2019 and simply states that the Companies' planned pension contributions in 2020 to 2022 are less than the amount of pension expense included in rates. His analysis does not consider the significant pension contributions made in 2018 as shown in Rebuttal Exhibit CMG-3 nor does it consider that the Companies have developed their pension expense for ratemaking purposes based on reports from its independent actuaries. In fact, the

[27] Case No. 2014-00371, Order at 4-5 (Ky. PSC June 30, 2015); Case No. 2014-00372, Order at 5 (Ky. PSC June 30, 2015).

Companies have filed rate cases on a regular basis utilizing reports from its actuaries to develop the pension expense included in rates. Thus, there is no reason to believe the Companies have significantly over recovered their pension costs.

Q. Should Mr. Kollen's adjustment and Mr. Gorman's recommendation regarding pension and OPEB related assets and liabilities be denied?

A. Yes. For the reasons cited above, most notably the significant net benefit currently being provided to customers by the inclusion of these assets and liabilities in rate base and capitalization, this adjustment should be denied.

III. OTHER CASH WORKING CAPITAL ADJUSTMENTS

Q. Do the Companies agree with Mr. Kollen's other adjustments to cash working capital?

A. No. Because Mr. Kollen argues that the Companies should use rate base in lieu of capitalization, he recommends several corrections to the Companies' current calculation of rate base contained in its reconciliation, in addition to the correction to non-cash pension and OPEB related assets and liabilities discussed above.

A. Clearing Accounts

Q. What activity is included in the clearing accounts on Schedule B-5.2 F?

A. The balances in Account 184 as of August 2020 reflected eight months (January through August 2020) of net credits for service cost, interest cost, and estimated return on assets recorded for pensions and OPEBs. These balances were cleared to Account 128 *Prepaid Pension* and Account 228.3 *Accumulated Provision for Postretirement Benefits* as of December 31, 2020 on an actual basis but were not cleared for forecasting purposes. As discussed in the responses to AG-KIUC 1-54, the forecasted pension and postretirement expense (activity from September 2020 forward) is reflected as changes in Account 128 *Prepaid Pension* and Account 228.3 *Accumulated Provision for Postretirement Benefits* for the service cost, interest cost, and estimated return on asset components of net periodic pension and postretirement costs.

Q. Why did the Companies choose not to clear these balances for forecasting purposes?

A. The Companies chose not to clear or reclassify the August 2020 pension and OPEB balances recorded to Account 184 as a matter of administrative efficiency and good practice. The additional step to clear or reclassify the balances in Account 184 to the respective pension and OPEB balance sheet accounts in December 2020 would have no impact on total rate base and was therefore unnecessary from a forecasting standpoint.

Q. Do the Companies agree with Mr. Kollen's assertion that the clearing accounts should be set to zero or removed from rate base?

A. No, the Companies decision not to set the accounts to zero or reclassify the clearing account balances had no effect on the revenue requirement. Additionally, the clearing accounts and associated ADIT (which Mr. Kollen has improperly ignored) have been included in the pension and OPEB related accounts analysis shown on Rebuttal Exhibits CMG-4 and CMG-5. The determination of whether this should be included in rate base should be based on this analysis given the composition of the clearing account balances.

Q. Should the Commission deny Mr. Kollen's adjustment regarding clearing accounts?

A. Yes. For the reasons cited above, Mr. Kollen's adjustment regarding clearing accounts should be rejected.

B. Corrections to Account 186 for Long Term Service Agreements

Q. Do the Companies agree with Mr. Kollen's adjustment to reduce Account 186 to correct the Companies' errors in projected Long Term Service Agreements ("LTSA") balances?

A. Yes, the Companies agree that the balance of the LTSA included in rate base should be adjusted for the correction as Mr. Kollen indicated at pages 65 and 66 of his testimony. However, this correction was included in the Companies' February 26, 2021 errata filing.[28] Accordingly, the adjustment for this correction has been incorporated into the first adjustment on Table 1 – "Utilize Rate Base Instead of Capitalization to Reflect Return on Component for Base Rates" and removed from the fifth adjustment on Table 1 – "Reduce Account 186 to Correct Company Error in Projected Balances."

Q. Do the Companies agree with Mr. Kollen's adjustment to remove 95% of the balance in Account 186 for the LTSA?

A. No, as discussed in the Rebuttal Testimony of Kent W. Blake, the Companies oppose the use of AFUDC for ratemaking purposes, except for the AMI proposal. Furthermore, the Companies are not permitted to record AFUDC on amounts recorded to Account 186 (per FERC Uniform System of Accounts, construction costs are included in Utility Plant accounts, not Account 186) thus Mr. Kollen's proposal would

[28] Companies' errata filing on February 26, 2021, Supplemental Response to PSC 1-56: KU correction No. 1 - Correction to CR7 LTPC and Brown LTSA deferred debits on Schedule B-5.2 Cash Working Capital Components. (KU AG-KIUC 2-28, parts e and k); LG&E Correction No. 2 Correction to CR7 LTPC and Brown LTSA deferred debits on LG&E electric Schedule B-5.2 Cash Working Capital Components. (LG&E AG-KIUC 2-22, parts e and k).

deny the Companies the ability to recover its associated carrying costs for payments made prior to the outage work performance. Accordingly, Mr. Kollen's adjustment to remove 95% of Corrected 186 Balance to Reflect as CWIP should be rejected.

C. Offset to CWIP for Vendor Financing (Accounts Payable)

Q. Do the Companies agree with Mr. Kollen's assertion that the Companies did not offset the CWIP in rate base for the related accounts payable to reflect the vendor financing?

A. No, Mr. Kollen's assertion is incorrect. The Companies ***included*** the offset for CWIP in rate base for the related accounts payable as shown on Schedule B-5.2 F.[29] The offsets are included on Schedule B-5.2 F (Line 13 for KU and Line 12 for LG&E Electric and LG&E Gas). Furthermore, the Companies also included the offset for RWIP in rate base for the related accounts payable on Schedule B-5.2 F (Line 14 for KU and Line 13 for LG&E Electric and LG&E Gas). The Companies pointed out how it addressed the associated CWIP amounts in Accounts Payable in its response to AG-KIUC 2-10. Accordingly, Mr. Kollen's adjustment to Reduce CWIP by the Amount of Vendor Financing in Accounts Payable should be rejected to avoid his duplication error.

IV. EXCESS ADIT ISSUES RELATING TO MR. KOLLEN'S PROPOSED ADJUSTMENTS

Q. Has Mr. Kollen addressed the excess ADIT impacts associated with his proposed adjustments?

[29] *See* Companies' errata filing on February 26, 2021, Supplemental Response to PSC 1-56. Correction to June 2022 Net Accrued Retention/CWIP and Net Accrued RWIP on Schedule B-5.2 Cash Working Capital Components.

A. No. Mr. Kollen has not addressed the excess ADIT impacts for the exclusion of pension and OPEB related asset and liability amounts from rate base; the reduction in depreciation rates for Brown Unit 3 and Mill Creek Units 1 and 2 if the AG/KIUC claim to reject the proposed depreciation rates for these three generation units is sustained.

Q. Is this appropriate?

A. No. Both of these adjustments have significant excess ADIT implications which must be addressed. I will address each of these issues separately below.

Q. Why should excess ADIT impacts be considered as it relates to Mr. Kollen's proposal to exclude pension and OPEB related asset and liability amounts from rate base?

A. As discussed in Part II above, the significant pension contributions made in 2018 were largely the driver for the pension liabilities changing to prepaid pension assets in 2019. The Companies were able to deduct the 2018 pension contributions on their 2017 tax returns yielding significant excess ADIT benefits (shown in Rebuttal Exhibits CMG-4 and CMG-5) which are proposed to be returned to customers as part of these proceedings via the Economic Relief Surcredit. Should the Commission choose to accept Mr. Kollen's proposal to remove the pension assets and related liabilities from rate base, an adjustment should be made to *reduce* the Economic Relief Surcredit to avoid unfairly harming the Companies from the mismatch in tax treatment. Additionally, the ADIT balances utilized in the rate base adjustment should be prorated and include the associated excess ADIT regulatory liability.

Q. Why should excess ADIT impacts be considered as it relates to Mr. Kollen's proposal to reduce the depreciation expense for Brown 3 and Mill Creek 1 and 2?

A. When book depreciation expense is decreased as a result of using longer depreciable lives, the revenue requirement is increased by the lower excess ADIT amortization. "Protected" excess ADIT is reduced and refunded to customers over the remaining book lives of property that gave rise to the deferred taxes using the Average Rate Assumption Method ("ARAM"). For any change made to extend the book lives of property, an adjustment is required to reduce the excess ADIT amortization to avoid a potential normalization violation. The corresponding rate base and excess ADIT adjustments were not included as part of Mr. Kollen's proposed adjustments. The Companies have utilized a quarterly proration for the ADIT rate base adjustment calculations (including excess ADIT regulatory liability) consistent with the Companies' filed position and normalization requirements.[30] The impact of these corrections to the revenue requirement are shown in Rebuttal Exhibit CMG-7: KU $6.050 million and LG&E Electric $5.129 million.

Q. Are there other excess ADIT adjustments that also must be addressed in these proceedings?

A. Yes. As discussed in the Companies' response to AG-KIUC 2-8(g), the Companies have become aware of an issue that will necessitate a change in its amortization of excess ADIT as a result of a recently issued Private Letter Ruling ("PLR") from the Internal Revenue Service ("IRS").

[30] 26 CFR 1.167(l)-1(h).

Q. Briefly describe the issue raised and conclusion reached in the recently released IRS Private Letter Ruling.

A. In August 2020, the IRS released PLR 202033002, regarding the Tax Cuts and Jobs Act ("TCJA") excess deferred tax normalization rules. In the PLR, the IRS addressed the issue as to whether cost of removal ("COR") is "protected" by the normalization rules of section 168(i)(9)(A).

The IRS ruled in the PLR that COR is not "protected" by IRC §168 deferred tax normalization rules and, thus, presumptively not "protected" by the TCJA excess deferred tax normalization rules. Although the PLR is non-binding for other taxpayers, the conclusion reached needs to be evaluated by taxpayers.

Q. Why is this an issue for the Companies?

A. The Companies' ARAM calculation previously utilized a composite book depreciation rate (which includes COR accrual) to reverse protected method/life timing differences. Similarly, the Companies had included their COR deferred tax assets within their method/life deferred tax liabilities. This treatment accelerates the reversal of the Companies' protected ADIT liability and is not in accordance with the normalization requirements per the PLR finding.

Q. Based on the conclusion reached in the PLR by the IRS, what is the Companies' position with regards to this matter in these proceedings?

A. The Companies must update their ARAM calculation to ensure strict compliance with the normalization requirements as set forth in the Treasury regulations resulting in the following revenue requirement increases from the Companies' filed position: KU

$1.638 million; LG&E Electric $1.685 million; and LG&E Gas $0.386 million.[31] Rebuttal Exhibit CMG-7 provides the impact of this change to the revenue requirement for the AG-KIUC's proposed position to reduce the depreciation expense for Brown Unit 3 and Mill Creek Units 1 and 2: KU $1.495 million and LG&E Electric $1.464 million.

V. REMOVAL OF CWIP AND CAPITALIZATION OF CONSTRUCTION FINANCING COSTS USING AFUDC

Q. Please explain Mr. Kollen's recommendation regarding the Companies' Construction Work in Progress ("CWIP").

A. Mr. Kollen recommends the Commission exclude CWIP from rate base or capitalization, depending on the methodology adopted by the Commission for the valuation of the Companies' properties for ratemaking, and direct the Companies to accrue AFUDC starting with the date when base rates are reset in this proceeding. In support of his argument, he asserts that the Companies will fully recover construction financing costs under the AFUDC approach. He recommends that the Commission exclude CWIP from rate base (if the AG/KIUC recommendation to use rate base is adopted) or capitalization (if the AG/KIUC recommendation to use rate base is not adopted) and direct the Companies to accrue AFUDC starting with the date when base rates are reset in this proceeding.

Q. Has Mr. Kollen recommended this before?

A. Yes. Mr. Kollen submitted nearly identical testimony on this issue during the Companies' last base rate proceedings in 2018.

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[31] Attachment provided in response to AG-KIUC 2-8(g).

Q. As a result of the 2018 rate case, were the Companies required to deviate from their longstanding practice of including CWIP in rate base?

A. No. The Companies have continued using the CWIP methodology, which allows the carrying costs on capital investments in projects under construction to be recovered through current rates.

Q. Please explain the benefits of CWIP compared to AFUDC for construction financing costs.

A. Many benefits exist, including lower capitalized costs, stable cash flows, and improved quality of cash earnings. The *Accounting for Public Utilities* treatise identifies the following benefits:

- Because CWIP has the lower capitalized costs, the inclusion of CWIP in rate base actually reduces the total cost to the utility and its customers over the life of the plant.[32]

- Inclusion of CWIP in rate base also causes increased cash flows and allows the utilities to avoid a certain amount of outside financing, which is advantageous whenever incremental borrowing costs exceed embedded costs.[33]

- Increased cash flows and less outside financing lead to an improved quality of actual cash earnings. Because securities analysts and bond rating agencies focus on cash flow and cost deferrals, the improved quality of cash earnings may allow required financings at relatively lower costs.[34]

- The greater risk associated with higher levels of non-cash earnings, such as AFUDC, would ultimately be reflected in higher rates of return required by investors.[35]

[32] *See* Rebuttal Exhibit CMG-8: Accounting for Public Utilities, § 4.04[4].
[33] *Id.*
[34] *See id.*
[35] *See id.*

- Investors recognize that including CWIP in rate base is an important tool that supports the utility's financial integrity and attenuates some of the financial risks associated with new infrastructure investment.[36]

Q. Please review the Companies' historical use of CWIP.

A. The Commission has authorized the use of CWIP for ratemaking since at least the 1970s to address the impact of construction costs on utilities' financial integrity.[37] Like the long-standing use of capitalization as the valuation policy for the Companies' property for ratemaking discussed earlier in this testimony, both CWIP and capitalization are long-standing policies of this Commission for the Companies.

Indeed, in LG&E's 1983 rate case, the Commission noted in its final order, "LG&E had never accrued AFUDC."[38] The Commission further observed, "[t]his means that the present ratepayers are paying less because of financing costs paid by prior ratepayers."[39] In rejecting the argument by intervenors to adopt the AFUDC approach, the Commission further remarked that it was "painfully aware that a switch to the accrual of AFUDC could lead to grave difficulties later" and expressly held that the historical treatment of CWIP should continue.[40]

In the course of denying the Attorney General and other intervenors' petitions for rehearing on the CWIP issue, the Commission stated:

> "LG&E's electric rates are lower now, due to the current CWIP policy, than if AFUDC had been accrued on prior construction projects. These lower rates result from a lower rate base, lower return requirement and lower depreciation expense. A cash return on CWIP also benefits ratepayers through lower financing

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[36] *See id.*
[37] *The Treatment of CWIP, Eugene F. Brigham, Public Utility Research Center Working Paper* 5-81 (October 1981), available at: https://bear.warrington.ufl.edu/centers/purc/docs//papers/8111_Brigham_The_Treatment_of.pdf.
[38] *General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 8924, Order at 28-29 (Ky. PSC May 16, 1984).
[39] *Id.* at 28-29.
[40] *Id.* at 36.

> costs due to improved financial ratios and reduction in risk as perceived by the investment community."[41]

In addition, the Kentucky courts have also upheld the Commission's decision to allow CWIP accounting for LG&E.[42]

Because the Commission has never directed the Companies to change their CWIP methodology, the Companies' rate bases are much lower than they otherwise would be and their embedded cost of debt is relatively low. These two factors have helped the Companies over time to have some of the lowest rates per kWh in the nation.

Q. Aren't the Companies proposing the use of AFUDC in these proceedings?

A. Yes, but only for a specific and limited purpose. The Companies are proposing to accrue AFUDC for the capital and financing costs during the implementation of the AMI project only. This ratemaking treatment is necessary to achieve the Companies' objective of full AMI implementation with no customer bill impact. The Companies are adamantly opposing Mr. Kollen's recommendation to transition to the AFUDC methodology for capitalizing financing costs incurred during construction. The limited use of AFUDC is discussed in more detail in Mr. Blake's Rebuttal Testimony.

Q. Have other regulators recognized the potential benefits associated with including CWIP in rate base?

[41] Case No. 8924, Order at 2 (Ky. PSC June 25, 1984).
[42] *Jefferson County Fiscal Court v Kentucky Public Service Commission*, Opinion and Order, 29 PUR4th, pp. 143-144 (Franklin Circuit Court March 15, 1977) ("The commission was on ground when it allowed LG&E to include CWIP in rate base. The evidence is uncontradicted that, for many years, LG&E (with commission approval) has included CWIP in its rate base, but it has not increased its earnings by allowance for funds used during construction (AFUDC). Therefore, LG&E's rate base is smaller, and its revenue requirements are less that they would have been had its rate base included an AFUDC component. There is respectable authority for the proposition that the policy of including CWIP in rate base, and of paying construction costs currently, instead of mortgaging the future, is the sounder approach because it costs consumers less in the long run.").

A. Yes. Investors recognize that it is not uncommon for regulators to include CWIP in rate base when establishing rates. Studies prepared by Pacific Economics Group Research LLC and Edison Electric Institute show that more than 21 states have recent electric utility precedents for CWIP in rate base.[43]

Q. Mr. Kollen suggests that the AFUDC approach "provides the Companies dollar for dollar recovery of its actual construction financing costs, no more and no less" at page 69 of his testimony. Do you agree with this statement?

A. No. Mr. Kollen appropriately notes that the methodology of the FERC requires the Companies to first assign its short-term debt balance to CWIP and applies the weighted average of long-term debt and common equity only to any residual amount of financing costs. In addition, the FERC methodology also only allows a calculation of the weighted cost of capital as of the beginning of the year to be applied for the entire calendar year with adjustments to that calculation only being made in limited circumstances. Rebuttal Exhibit CMG-10 shows that the weighted average cost of capital that the Companies would use to accrue AFUDC under this methodology for the forecasted test period would be 2.48% for KU, 1.59% for LG&E Electric, and 5.25% for LG&E Gas or 473, 558, and 192 basis points lower than the actual weighted average cost of capital for KU, LG&E Electric, and LG&E Gas operations.[44] The FERC methodology also contains rules as to the timing of these calculations which were not used in Rebuttal Exhibit CMG-10 in order to simplify the calculations and

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[43] *See* Rebuttal Exhibit CMG-9: Pacific Economics Group Research LLC, *Alternative Regulation for Evolving Utility Challenges: An Updated Survey* (January 2013); Edison Electric Institute, *Forward Test Years for US Electric Utilities* (August 2010).

[44] The Companies propose to accrue AFUDC using the Companies' weighted average cost of capital during the AMI implementation period. *See* Direct Testimony of Kent W. Blake at 13.

limit them to data already contained in the record of these proceedings. Interestingly, despite Mr. Kollen's understanding the FERC methodology, he calculated the revenue requirement impact of removing CWIP from the Companies' revenue requirement using their weighted average cost of capital, rather than removing it from short-term debt first and then allocating any remaining balance on a pro rata basis between long-term debt and equity. This difference between the Companies actual weighted average cost of capital and the FERC AFUDC methodology would not provide the Companies a full recovery of its actual construction financing costs.

Q. Mr. Kollen asserts that AFUDC is consistent with generally accepted accounting principles ("GAAP") at page 70 of his direct testimony. Is this a credible argument for the use of AFUDC?

A. No. The Companies have decades of history of including CWIP in capitalization and rate base and not recording AFUDC for its Kentucky and Virginia retail jurisdictions. That treatment has been reflected in their published financial statements filed with the Securities and Exchange Commission. Those financial statements have always been prepared in accordance with GAAP as evidenced by the unqualified audit opinions received and included with those financial statements. To put a finer point on this, in accordance with ASC 980-835-25-1 and 30-1, AFUDC should be capitalized only during periods of construction and only if it is probable that the regulated utility will receive subsequent recovery through the ratemaking process. Any amounts that are not probable of recovery should not be capitalized. Furthermore, pursuant to ASC 980-835-25-2, if AFUDC is not capitalized because future recovery through rates is not probable, the regulated utility should not alternatively capitalize interest cost under ASC 835-20, Interest – Capitalization of Interest.

Q. Mr. Kollen also makes multiple contentions in support of AFUDC that it depreciates the construction financing costs over the useful life of the asset, somehow avoiding intergenerational inequities. Do you agree?

A. No. The trade-off is that AFUDC involves the compounding effect of those construction financing costs, meaning those financing costs increase the amount capitalized and increases the cost of capital recovered by the Companies over the life of the assets. More importantly, this traditional AFUDC vs. CWIP argument is significantly mitigated in the case of the Companies. As shown in Rebuttal Exhibit CMG-11, over half (52%) of the thirteen-month average CWIP balance of the Companies for the forecasted test period represents projects in service by the end of the forecasted test period. Of those projects not yet in service by the end of the forecasted test period, Rebuttal Exhibit CMG-11 also shows that the weighted average time period before going into service is only about eleven months beyond the end of the forecasted test period.

Q. If the Commission were to consider Mr. Kollen's recommendation to require the Companies to switch from CWIP in capitalization and rate base to use of AFUDC, do Mr. Kollen's calculations produce an accurate revenue requirement impact of this?

A. No. As noted above, the revenue requirement impact of removing CWIP from capitalization would have to employ the same FERC weighted average cost of capital methodology used to accrue AFUDC in order to provide the Companies an opportunity to recover their construction financing costs. In addition, Mr. Kollen removed the incorrect CWIP balance because he utilized his CWIP accrual adjustment rather than the Companies' adjustment provided on Schedule B-5.2 F as discussed above. Rebuttal Exhibit CMG-12 includes a revised calculation of the revenue requirement impact of this change in methodology. As shown in that exhibit, these two adjustments reduce Mr. Kollen's proposed KU revenue requirement reduction from $12.3 million to $3.8 million, LG&E's electric revenue requirement reduction from $5.2 million to $1.0 million, and LG&E's gas revenue requirement reduction from $3.8 million to $3.0 million.

Q. Do you agree with Mr. Kollen's recommendations?

A. No. For the reasons noted above the Commission should not deviate from its long-established support for including CWIP in the Companies' capitalization and rate base. In addition to the reasons noted above, the Companies would have to leave behind decades of CWIP accounting and create completely new accounting protocols to conform to AFUDC accounting. Even more important than the administrative burden, if the Commission were to direct the Companies to accrue AFUDC instead of allowing CWIP, the cash flow and quality of earnings impacts would negatively affect the Companies.

In response to AG-KIUC 1-104, the Companies provided a report by Moody's affirming the current stable ratings of the Companies and noting the Companies' inclusion of CWIP in base rates as a credit positive.[45] But the report cautions that the

[45] KU Response to Joint Initial Data Requests of the Attorney General and KIUC Dated January 8, 2021, AG-KIUC 1-104, Attachment 3: *Credit Opinion, Kentucky Utilities Company,* Moody's Investors Service, at 5 (Oct. 23, 2020); *Credit Opinion, Louisville Gas & Electric Company*, Moody's Investors Service, at 5 (Oct. 23, 2020).

stable outlook for KU and LG&E reflects Moody's expectation that the regulatory environments will remain credit supportive and incorporates Moody's view that KU and LG&E "will continue to generate stable cash flow and adequate financial metrics…."[46] An Order directing the Companies to switch from a ratemaking methodology in place for decades to one that adversely impacts funds from operations ("FFO") and calls into question the quality of earnings would not be viewed favorably by credit rating agencies. The elimination of cash recovery of construction financing costs replaced by non-cash AFUDC earnings for the forecasted test period, as recommended by Mr. Kollen, would adversely impact the Companies' FFO/Debt metrics.

VI. GENERATOR OUTAGE EXPENSE NORMALIZATION AND DEFERRAL ACCOUNTING

Q. Briefly describe the Companies' proposal to normalize generator outage expense.

A. As explained in my Direct Testimony and confirmed by Mr. Kollen, the Companies used historical expenses for 2017 through August 2020 and forecasted expenses for September 2020 through 2024 to develop the eight-year average of generator outage expense included in the forecasted test year. The Companies' proposal also seeks to continue the use of deferral accounting to true-up any difference between actual costs and the amounts included in the forecasted test year.

Q. Does Mr. Kollen claim the Companies' proposed normalization calculation is unreasonable?

[46] LG&E Response to Joint Initial Data Requests of the Attorney General and KIUC Dated January 8, 2021, AG-KIUC 1-104, Attachment 3: *Credit Opinion, Kentucky Utilities Company,* Moody's Investors Service, at 2 (Oct. 23, 2020); *Credit Opinion, Louisville Gas & Electric Company*, Moody's Investors Service, at 2 (Oct. 23, 2020).

A. Yes. Mr. Kollen asserts that the Companies' calculation is unreasonable since it takes into account multiple forecasted years because "[t]he future is inherently unknown and uncertain."[47] Mr. Kollen further asserts that the current true-up mechanism and associated deferral accounting treatment provides an uneconomic behavioral incentive and encourages excessive expenses.

Q. Please briefly describe Mr. Kollen's recommendation regarding generator outage expenses.

A. Mr. Kollen recommends the Commission normalize the generation outage expense in the test year by using an average of the Companies' most recent historical actual eight years of outage expenses, adjusted to exclude the outage expense for generating units already retired and escalated for inflation to the test year. Mr. Kollen also proposes to eliminate the true-up of outage expenses and associated deferral accounting. And lastly, Mr. Kollen proposes to not provide the Companies recovery of its carrying costs for prior outage expense deferrals given his rate base valuation proposal.

Q. Is Mr. Kollen's proposal reasonable?

A. No. Mr. Kollen's proposal is not only selective and results oriented, it is also unfair and unreasonable in that it denies the Companies the ability to recover its cost of capital. The Companies only agreed to the use of a five-year historical average in the previous case as part of a mutually agreed settlement. The Companies agreed to this based on the understanding that not only would it be allowed to true-up its outage expenses, but it would also be afforded the opportunity to recover its carrying costs for any resulting under recoveries. In fact, the Companies' own projections indicated that a significant

[47] Direct Testimony of Lane Kollen at 84.

under recovery would result given the abnormally low five-year historical average proposed by Mr. Kollen.

Q. Why do the Companies believe Mr. Kollen's methodology is selective and results oriented?

A. First, Mr. Kollen's normalization approach does not appropriately account for replacement generation outage expenses. Second, Mr. Kollen's approach is inconsistent with his previous case proposal. Third, Mr. Kollen's proposal does not reflect the increase in outage expenses resulting from recent environmental upgrades. Lastly, Mr. Kollen's approach does not take into consideration the increase in outage expenses resulting from the elimination of ECR projects proposed in these proceedings.

Q. How does the Companies' approach ensure replacement generation outage expenses are appropriately considered?

A. The Companies' normalization approach appropriately reflects the increase in outage costs associated with Cane Run 7 while Mr. Kollen's approach does not. Mr. Kollen's normalization recommendation is skewed because it fails to incorporate an appropriate level of outage expenses for replacement generation necessitated by his removal of outage expenses for retired plants.

Q. How much does Mr. Kollen's recommendation include for Cane Run 7 outage expense compared to the Companies' proposal?

A. Mr. Kollen's eight-year historical average includes only $1.9 million for KU and $0.6 million for LG&E for Cane Run 7 outage expenses, while the Companies include $3.5 million for KU and $1.1 million for LG&E, as shown in Table 3 below.

Table 3					
Cane Run 7 Outage Expense					
AG/KIUC (Kollen)	**KU**	**LGE**	**Companies Filed Position**	**KU**	**LGE**
2013 Actuals			2017 Actuals	$ 1,856,219	$ 600,280
2014 Actuals			2018 Actuals	$ 955,333	$ 308,210
2015 Actuals	$ 279,822	$ 90,532	2019 Actuals	$ 581,201	$ 176,213
2016 Actuals	$ 1,069,280	$ 350,401	2020 Actuals/Forecast*	$ 6,445,222	$ 1,939,610
2017 Actuals	$ 2,029,224	$ 656,227	2021 Forecast	$ 1,649,177	$ 496,299
2018 Actuals	$ 1,023,895	$ 330,330	2022 Forecast	$ 3,903,158	$ 1,174,607
2019 Actuals	$ 610,699	$ 185,156	2023 Forecast	$ 1,184,536	$ 356,472
2020 Actuals	$ 6,613,760	$ 1,990,329	2024 Forecast	$11,539,322	$ 3,472,616
Average	**$ 1,937,780**	**$ 600,496**	**Average**	**$ 3,514,271**	**$ 1,065,538**
*Eight months of Actuals and four months of Forecast					

Q. Why are the outage costs for Cane Run 7 so significant in the year 2024?

A. As discussed in Mr. Bellar's rebuttal testimony, this is the result of Cane Run 7 incurring its first major outage inspection in accordance with the LTPC along with the first major outage for the HRSG turbine. Importantly, this supports the Companies' position that the normalization period should be 2017 to 2024, not 2013 to 2020, to ensure the first full outage cycle for Cane Run 7 is included in the eight-year average.

Q. Is the Companies' proposal consistent with previous filings?

A. Yes, the Companies normalization proposal is consistent in both form and methodology with its previous two rate case filings. While Mr. Kollen's approach appears to support the Companies' position in regard to the eight-year outage cycle, it is evident that his proposal seeks to yield an expense level that will result in the Companies under recovering their actual costs. For example, Mr. Kollen strategically includes year 2013 outage expenses, which were abnormally low, in his calculation. Had Mr. Kollen used the same approach he put forth in the last base rate proceedings, i.e. a five-year average (2016 to 2020), his outage normalization adjustment would be reduced from ($3.9) million to ($1.2) million for KU and ($1.6) million to $0.2 million for LG&E.

Q. Have the Companies experienced an increase in outage expenses for the recent environmental upgrades at the various stations?

A. Yes, not only have the costs increased as a result of the environmental upgrades as discussed in Mr. Bellar's rebuttal testimony, but also the complexity and duration of the outages have increased.

Q. Does Mr. Kollen's proposal accurately provide for the outage maintenance costs that are moving from the ECR mechanism into base rates?

A. No. As discussed in Mr. Conroy's Direct Testimony, the Companies are proposing to eliminate certain projects from their ECR mechanisms and recover the revenue requirements associated with these projects in base rates.[48] Mr. Kollen's proposal regarding outage maintenance costs does not consider this issue and thus outage maintenance costs will be under recovered by $0.2 million for KU and $0.3 million for LG&E.

Q. Do the Companies agree with Mr. Kollen's and Mr. Bieber's argument that the Companies' proposed true-up mechanism provides an uneconomic behavioral incentive and encourages excessive expenses?

A. No, not at all. As discussed in the Companies' response to PSC 2-31 (KU) and PSC 2-34 (LG&E), the Companies proposal to continue deferral accounting treatment for outage expense is centered around providing the Companies the ability to recover their prudently incurred outage expenses, while at the same time smoothing out the fluctuations in outage expense due to the inspection cycle. Under the Companies' proposal and subject to review in rate cases, the Companies will recover no more and

[48] Direct Testimony of Robert M. Conroy at 15-16.

no less than their prudently incurred cost for planned generation outages. Thus, there is absolutely no incentive for the Companies to risk disallowance for imprudent spending as the Companies are only being provided recovery of their costs.

Q. Has the Companies approach to outage expense management served to benefit customers?

A. Yes. As discussed in the Direct Testimonies of Mr. Thompson and Mr. Bellar, the Companies have experienced outstanding generation performance and have attained significant operational achievements in regard to its generation of electricity. Most recently, as discussed in Mr. Bellar's Rebuttal Testimony, the Companies' systems performed reliably during the severe weather events in February. In addition to operational excellence, the Companies also manage their costs and are top quartile performers among peer vertically-integrated utilities for cost control.[49] The Companies' customers benefit from safe and reliable service at low operating costs.

Q. What is your recommendation regarding generator outage normalization?

A. For the reasons stated above, it is my recommendation that the Commission deny Mr. Kollen's historical based methodology to normalize planned generation outage expense and instead accept the Companies' proposal, which is more accurate and reflective of the level of outage expenses the Companies will truly incur. Furthermore, the Companies strongly recommend that the true-up and associated deferral accounting treatment be continued to ensure the Companies recover no more and no less than their prudently incurred outage expenses.

[49] Direct Testimony of Paul M. Thompson at 9-10.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Christopher M. Garrett**, being duly sworn, deposes and says that he is Controller for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

DocuSigned by:
Christopher M. Garrett
5B353C6395DE4D7...
Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 6th day of April 2021.

Judy Schooler
Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

Rebuttal Exhibit
CMG-1 is
being provided in a
separate file in Excel
format.

Kentucky Utilities Company's
Annual Report of Nonregulated Activities

Required by 807 KAR 5:080
Calendar Year 2020

Filed with the Kentucky Public Service Commission on March 31, 2021

Index to the Annual Reporting of
Kentucky Utilities Company - Calendar Year 2020

DATA REQUIREMENT	SOURCE	REPORT
Description of Change to Cost Allocation Manual	807 KAR 5:080, Section 2 (1)(a)	For many years, KU has used its LG&E and KU Services Company Cost Allocation Manual for affiliate cost allocations. KU began utilizing an updated Cost Allocation Manual, effective January 1, 2020. *See* Case No. 2020-00349, Application Filing Requirement Tab 51. KU uses the fully-distributed cost method pursuant to KRS 278.2203(2)(a). The costs associated with the non-regulated activities described in this Report are directly assigned and are consistent with the requirements in the Cost Allocation Manual.
Nonregulated activities	807 KAR 5:080, Section 2 (1)(b)	Exhibit A
List of nonregulated affiliates	807 KAR 5:080, Section 2 (1)(c)	Exhibit B
Copy of service agreements	807 KAR 5:080, Section 2 (2)	Exhibit C

Exhibit A

A report on the utility's incidental nonregulated activity that describes the activity and provides justification for reporting the nonregulated activity as an incidental nonregulated activity, including:

1. *Revenue per year or percentage of total revenue per year of the activity reported as an incidental nonregulated activity;*

2. *A calculation demonstrating the manner in which the affected utility has determined the percentage of revenue set forth in subparagraph 1 of this paragraph;*

3. *A full explanation as to why the activity reported as an incidental nonregulated activity is reasonably related to the affected utility's regulated services*

NONREGULATED ACTIVITIES OF KENTUCKY UTILITIES COMPANY
For Year Ended December 31, 2020

Activity	Revenues
Merchandise Sales[1] Occasional sale of goods from KU's warehouses to third parties.	$16,677
Total 2020 KU Nonregulated Revenue	$16,677
Total 2020 KU Operating Revenue	$1,690,963,437
Nonregulated % of Total Revenue	.00099%

[1] Gross Merchandising Revenue $16,677
Merchandising Cost of Sales (18,711)
Net Merchandising Revenue ($2,034)

Exhibit B

The list below shows only nonregulated (i.e. not regulated by the KPSC) affiliates of Kentucky Utilities Company ("KU") directly or indirectly owned by PPL Corporation, where such indirect or direct ownership exceeds 10%.

Certain entities shown are also regulated, in part, by other state utility commissions (PPL Electric Utilities Corporation ("PPL EU")), by the Federal Energy Regulatory Commission (PPL EU and Electric Energy, Inc.), or by Ofgem in the United Kingdom (the four Western Power Distribution electricity distribution companies).

Name	Nature of Business
2711171 Ontario Inc.	Holding company (minority interest)
Aztec Insurance Limited	Captive insurance company located in Guernsey
Bulloch County GA S1, LLC	Solar energy company
Central Networks Trustees Limited	Dormant company
CEP Commerce, LLC	Holding company
CEP Lending, Inc.	Finance company for PPL Corporation and its affiliates
CEP Reserves, Inc.	Finance company for PPL Corporation and its affiliates
Chambersburg Solar Center, LLC	Solar energy company
Demand Power Group Inc.	Canadian renewable energy company (minority interest)
DHA, LLC	Community housing lending fund in Louisville (minority interest)
East Brunswick Solar LLC	Solar energy company
Electralink Limited	Data Transfer Service operator in connection with the operation of the competitive electricity supply market in England, Scotland and Wales
Electric Energy, Inc.	Illinois power plant owner/operator and wholesale power seller (minority interest)
Envista Energy LP	Canadian renewable energy company
FCD LLC	Lessee of river coal dock in Western Kentucky
Franklin County GA S1, LLC	Solar energy company
Gemserv Limited	Consulting services provider serving utility and other markets in the UK and Europe
Greene County GA S1, LLC	Solar energy company
Hyder Limited	In liquidation
Hyder Profit Sharing Trustee Limited	Dormant company
Infralec 1992 Pension Trustee Limited	Dormant company
Jackson Solar LLC	Solar energy company
Joppa & Eastern Railroad Company	Owner of certain spur railroad rights in Illinois (minority interest)
Kelston Properties 2 Limited	Owner a single property that is leased to a major supermarket group
Lexington Utilities Company	Dormant company
LG&E and KU Capital LLC	Holding company
LG&E and KU Energy LLC	Holding company
LG&E and KU Foundation Inc.	Charitable foundation
LG&E and KU Hydro I LLC	Dormant company
LG&E and KU Services Company	Centralized service company providing administrative, managerial and technical goods and services to affiliates
LG&E Energy Inc.	Dormant company
Lowndes County GA S1, LLC	Solar energy company
Lowndes County GA S2, LLC	Solar energy company
Mainely Solar, LLC	Solar energy company (majority interest)
Meriwether County GA S1, LLC	Solar energy company
Met-South, Inc.	Operator/marketer with respect to coal combustion byproducts and facilities (minority interest)
Meter Operator Services Limited	Dormant company
Meter Reading Services Limited	Dormant company
Midwest Electric Power, Inc.	Illinois power plant owner/operator and wholesale power seller (minority interest)
Murray County GA S1, LLC	Solar energy company
PMDC International Holdings, Inc.	Holding company
PP&L Residual Corporation	Dormant company
PPL (Barbados) SRL	Holding and finance company
PPL Atlantic Holdings, LLC	Holding Company
PPL Canada GP ULC	Canadian company serving as general partner in Canadian partnership

PPL Canada Holdings Inc.	Holding company
PPL Capital Funding, Inc.	Financing company for PPL Corporation and its affiliates, other than PPL Electric Utilities Corporation
PPL Corporation	Holding company
PPL Distributed Energy Resources, LLC	Renewable energy company
PPL Electric Utilities Corporation	Transmission and distribution company regulated by the Pennsylvania Public Utility Commission
PPL Energy Holdings, LLC	Holding company
PPL Energy Funding Corporation	Holding company
PPL Energy Resources, LLC	Holding company
PPL EU Services Corporation	Services provider for PPL Electric Utilities Corporation and its affiliates
PPL Foundation	Charitable foundation
PPL Global, LLC	Holding company
PPL Island Limited	Finance company for WPD affiliates
PPL Midlands Limited	Property investment company
PPL Power Insurance Ltd.	Captive insurance company located in Bermuda
PPL Renewables, LLC	Holding company and developer of renewable projects
PPL Safari Holdings, LLC	Holding Company
PPL Services Corporation	Services provider for PPL Corporation and its affiliates
PPL Strategic Development, LLC	Engages in development, acquisition and divestiture activities for affiliates
PPL Subsidiary Holdings, LLC	Holding company
PPL Technology Ventures, LLC	Holding and finance company
PPL TransLink, Inc.	Dormant company
PPL UK Holdings, LLC	Holding company
PPL UK Investments Limited	Holding company
PPL UK Resources Limited	Holding and finance company for WPD affiliates
PPL UK Distribution Holdings Limited	Dormant company
PPL WEM Limited	Holding and finance company
PPL WPD Investments Limited	Holding company
PPL WPD Limited	Holding company
Putnam County GA S1, LLC	Solar energy company
Safari Baboon, LLC	Solar energy company
Safari Chimpanzee, LLC	Solar energy company
Safari Donkey, LLC	Solar energy company
Safari Elephant, LLC	Solar energy company
Safari Energy Construction, LLC	Solar energy company
Safari Energy Georgia 1-2019, LLC	Solar energy company
Safari Energy Georgia 2-2019, LLC	Solar energy company
Safari Energy Georgia 3-2019, LLC	Solar energy company
Safari Energy Georgia 4-2019, LLC	Solar energy company
Safari Energy Georgia 5-2020, LLC	Solar energy company
Safari Energy Georgia 6-2020, LLC	Solar energy company
Safari Energy Georgia 7-2020, LLC	Solar energy company
Safari Energy Georgia 8-2020, LLC	Solar energy company
Safari Energy Illinois 1-2019, LLC	Solar energy company
Safari Energy Illinois 2-2020, LLC	Solar energy company
Safari Energy Investments 1, LLC	Solar energy company
Safari Energy Massachusetts 1-2019, LLC	Solar energy company
Safari Energy Massachusetts 2-2019, LLC	Solar energy company
Safari Energy Massachusetts 3-2019, LLC	Solar energy company
Safari Energy Massachusetts 4-2020, LLC	Solar energy company
Safari Energy Massachusetts 5-2020, LLC	Solar energy company
Safari Energy New York 1-2020, LLC	Solar energy company
Safari Energy Ohio 1-2019, LLC	Solar energy company
Safari Energy Rhode Island 1-2020, LLC	Solar energy company
Safari Energy Rhode Island 2-2020, LLC	Solar energy company
Safari Energy, LLC	Solar energy company
Safari Kangaroo, LLC	Solar energy company
Safari Loris, LLC	Solar energy company
Safari Orangutan, LLC	Solar energy company
Safari Viper, .LLC	Solar energy company
Safari Zebra, LLC	Solar energy company
Sebago Solar, LLC	Solar energy company (majority interest)
Shane Solar, LLC	Solar energy company (majority interest)
Sheet Road Management Company Limited	Manages and controls surface water drainage assets (majority interest)
Solar Star Energy Center, LLC	Solar energy company

Solar Star Meridian Park, LLC	Solar energy company
South Wales Electricity Share Scheme Trustees Limited	Dormant company
South Western Helicopters Limited	Provider of electricity power line inspection services to regional electricity companies
Terrell County GA S1, LLC	Solar energy company
Troup County GA S1, LLC	Solar energy company
Ware County GA S1, LLC	Solar energy company
Ware County GA S2, LLC	Solar energy company
Wesleyan Solar Array, LLC	Solar energy company
Western Kentucky Energy Corp.	Dormant company
Western Power Distribution (East Midlands) plc	Electricity distribution company in the U.K.
Western Power Distribution (West Midlands) plc	Electricity distribution company in the U.K.
Western Power Distribution (South Wales) plc	Electricity distribution company in the U.K.
Western Power Distribution (South West) plc	Electricity distribution company in the U.K.
Western Power Distribution Investments Limited	Holding company includes a portfolio of properties
Western Power Distribution plc	Holding and finance company for WPD affiliates
Western Power Generation Limited	Electricity generating company operating in the U.K.
Western Power Pension Trustee Limited	Dormant company
Wilkinson County GA S1, LLC	Solar energy company
WPD Distribution Network Holdings Limited	Holding and finance company
WPD Foundation	Charitable foundation
WPD Investment Holdings Limited	Holding company
WPD Limited	Dormant company
WPD Limited (Guernsey)	Property investment company located in Guernsey
WPD Midlands Networks Contracting Limited	Dormant company
WPD Property Investments Limited	Property management company
WPD Share Scheme Trustees Limited	Dormant company
WPD Smart Metering Limited	Operator of electricity metering business
WPD Telecoms Limited	Fiber optic cable services company
WW Share Schemes Trustees Limited	Dormant company
Wyman Hill Solar, LLC	Solar energy company (majority interest)

Exhibit C

A copy of each service agreement existing on the effective date of KRS 278.2201 through 278.2219 and remaining in effect shall be filed as an attachment to the annual report required by this subsection. After the initial filing, an affected utility shall file only new or amended service agreements with the annual report.

See attached.

AMENDED AND RESTATED UTILITY SERVICES AGREEMENT

This Amended and Restated Utility Services Agreement (this "Agreement") is entered into as of the 15th day of December, 2020, by and between Kentucky Utilities Company ("KU-ODP"), a public utility organized under Virginia and Kentucky law and doing business in Virginia as "Old Dominion Power Company"; Louisville Gas and Electric Company ("LG&E"), a public utility organized under Kentucky law; LG&E and KU Energy LLC ("LKE"), a Kentucky limited liability company; LG&E and KU Services Company ("LK Services"), a Kentucky corporation; PPL Corporation ("PPL"), a Pennsylvania corporation; PPL Capital Funding, Inc. ("PPL Capital"), a Delaware corporation; PPL Services Corporation ("PPL Services"), a Delaware corporation; and PPL EU Services Corporation ("PPLEU Services"), a Delaware corporation (collectively, the "Affiliates").

WHEREAS, KU-ODP, LG&E, and LK Services are direct, wholly owned subsidiaries of LKE, and PPL Capital, PPL Services, and PPLEU Services are direct, wholly owned subsidiaries of PPL, the parent of LKE;

WHEREAS, LK Services has been formed for the purpose of providing goods and administrative, management, and other services to subsidiaries and affiliates of LKE, including the utility operations of KU/ODP and LG&E

WHEREAS, PPL Services and PPLEU Services (collectively, the "Pennsylvania Service Companies") have been formed for the purpose of providing goods and administrative, management and other services to subsidiaries and affiliates of PPL;

WHEREAS, PPL Capital has been formed for the purpose of providing financing for the operations of PPL and its Affiliates;

WHEREAS, KU-ODP is a public service company as that term is used in Chapter 4 of Title 56 of the Code of Virginia and a public service company as that term is used in other applicable portions of Title 56 of the Code of Virginia as administered by the State Corporation Commission ("Commission");

WHEREAS, the Affiliates are parties to an Amended and Restated Utility Services Agreement approved by the Commission in Case No. PUE-2015-00126 by Order Granting Authority dated February 24, 2016, and further approved by the Commission in Case No. PUR-2020-00256 by Order Granting Approval dated December 15, 2020.

WHEREAS, KU-ODP and LG&E believe that it is in their interest to provide for an arrangement whereby they may, from time to time and at their option, agree to purchase such goods and administrative, management, and other services, including third-party goods and services, from LK Services, LKE, PPL, PPL Services, and PPLEU Services;

WHEREAS, KU-ODP and LG&E, believe that is it is in their interest to provide telecommunication services, use of facility space, and other services to LK Services at their election;

WHEREAS, KU-ODP and LG&E desire an arrangement whereby PPL Capital may procure letters of credit for KU-ODP LG&E, or the other Affiliates;

WHEREAS, the procurement of such goods and services, at the sole election of KU-ODP and LG&E, may result in purchasing and operational efficiencies, or is otherwise administratively necessary, and is in the public interest and the interest of KU-ODP and LG&E;

WHEREAS, because KU-ODP and LG&E engage in the joint planning and operation of their respective electrical systems as an integrated generation and transmission system and mutual distribution systems, it is in the public interest for KU-ODP and LG&E to establish an arrangement whereby they may from time to time and at their option, agree to provide or receive services, construction, or goods on an emergency basis or otherwise to or from each other at cost less depreciation, and provide or receive interests in land from one another at cost;

WHEREAS, KU-ODP and LG&E desire an arrangement whereby LK Services may act as payment and billing agent for them; and

NOW, THEREFORE, in consideration of the mutual covenants contained herein and other valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, intending to be legally bound, hereby agree as follows:

1. GOODS AND SERVICES. LKE, LK Services, PPL, PPL Services, and PPLEU Services will supply certain goods and administrative, management, or other services to KU-ODP and LG&E similar to those supplied to other subsidiaries or affiliates of LKE and PPL. Such services and goods are and will be provided to KU-ODP and LG&E only at their request. LKE, LK Services, PPL, PPL Services, and PPLEU Services will procure certain goods and services needed by KU-ODP and LG&E from third-party vendors. Such third-party goods and services will be provided to KU-ODP and LG&E only at the request of KU-ODP and LG&E. LKE, LK Services, PPL, PPL Capital, PPL Services, and PPLEU Services will invoice KU-ODP and LG&E or their payment and billing agent, LK Services, at cost, for KU-ODP's or LG&E's portion of the costs of purchases of goods and services. KU-ODP and LG&E may supply telecommunication services, use of facility space, and other services to LK Services at the election of KU-ODP or LG&E. KU-ODP and LG&E will invoice LK Services, at their fully distributed cost.

2. LETTER OF CREDIT. PPL Capital will procure letters of credit for KU-ODP and LG&E. Such transactions will be invoiced at cost to the respective party or its payment and billing agent, LK Services.

3. PERSONNEL. LK Services and the Pennsylvania Service Companies will provide KU/ODP and LG&E such goods and services by utilizing the services of their, or their affiliates', executives, accountants, financial advisers, technical advisers, attorneys, and other persons with the necessary qualifications.

If necessary, LKE, LK Services, PPL, and Pennsylvania Service Companies, after consultation with and consent by KU-ODP and LG&E, may also arrange for the services of nonaffiliated experts, consultants, and attorneys in connection with the performance of any of the services supplied under this Agreement.

4. TRANSACTIONS BETWEEN KU-ODP AND LG&E. KU-ODP and LG&E may, from time to time, provide or receive such services, to or from each other, for the construction, ownership, operation or maintenance of their generation facilities and their respective distribution and transmission systems, as well as for retail business services. Such transactions will be invoiced at fully allocated cost and will occur only as reasonably required when KU-ODP and LG&E believe in good faith that such transactions will be to the advantage of KU-ODP and LG&E. KU-ODP and LG&E may, from time to time, provide or receive, at not more than cost less depreciation, goods purchased by either KU-ODP or LG&E. KU-ODP and LG&E may, from time to time, provide or receive interests in land from one another in the ordinary course of business for the construction, ownership, operation, or maintenance of their generation facilities and their respective distribution and transmission systems. Such transactions will be invoiced at cost to the respective party or its payment and billing agent, LK Services.

5. COMPENSATION AND ALLOCATION. As and to the extent required by law, LKE, LK Services, PPL, and the PPL Service Companies provide and will provide such goods and services at fully allocated cost in accordance with the requirements of the Cost Allocation Manual attached as Exhibit A. KU-ODP and LG&E, at their election, will provide services to LK Services at fully distributed cost.

6. TERMINATION AND MODIFICATION. Any party to this Agreement may terminate this Agreement, with respect to itself, by providing 60 days written notice of such termination to the remaining parties.

This Agreement is subject to termination or modification at any time to the extent its performance may conflict with the provisions of the Federal Power Act or the Public Utility Holding Company Act of 2005, as amended, or with any rule, regulation or order of the Federal Energy Regulatory Commission adopted before or after the making of this Agreement. This Agreement shall be subject to the approval of any state commission or other state regulatory body whose approval is, by the laws of said state, a legal prerequisite to the execution and delivery or the performance of this Agreement.

The authorization for this Agreement shall expire at the conclusion of five years beginning on the date this Agreement is given final approval by the Virginia State Corporation Commission, unless the Virginia State Corporation Commission extends its authorization.

7. BILLING AND PAYMENT. Unless otherwise agreed, payment for services provided by any of the parties to this Agreement shall be by making remittance of the amount billed or by making appropriate accounting entries on the books of the appropriate parties. Billing will be made on a monthly basis, with the bill to be rendered by the 25th of the month, and remittance or accounting entries completed within 30 days of billing. Any amount remaining unpaid after 30 days following receipt of the bill shall bear interest thereon from the date of the bill at annual rate of A1/P1 30-day Commercial Paper. At KU-ODP's and LG&E's request, LK Services may act as their payment and billing agent. Payment and billing services, include, but are not limited to, sending or receiving invoices, receiving or disbursing payment, and making appropriate accounting entries.

8. NOTICE. Where written notice is required by this Agreement, all notices, consents, certificates, or other communications hereunder shall be in writing and shall be deemed given when mailed by United States registered or certified mail, postage prepaid, return receipt requested, addressed as follows:

To KU-ODP:
One Quality Street
Lexington, Kentucky 40507
Attn: Corporate Secretary

To LG&E:
220 West Main Street
Louisville, Kentucky 40202
Attn: Corporate Secretary

To LKE:
220 West Main Street
Louisville, Kentucky 40202
Attn: Corporate Secretary

To LK Services:
220 West Main Street
Louisville, Kentucky 40202
Attn: Corporate Secretary

To PPL:
2 North Ninth Street
Allentown, Pennsylvania 18101
Attn: Corporate Secretary

To PPL Capital:
2 North Ninth Street
Allentown, Pennsylvania 18101
Attn: Corporate Secretary

To PPL Services:
2 North Ninth Street
Allentown, Pennsylvania 18101
Attn: Corporate Secretary

To PPLEU Services:
2 North Ninth Street
Allentown, Pennsylvania 18101
Attn: Corporate Secretary

9. GOVERNING LAW. This Agreement shall be governed by and construed in accordance with the laws of the Commonwealth of Kentucky, without regard to its conflict of laws provisions.

10. MODIFICATION. No amendment, change, or modification of this Agreement shall be valid unless made in writing and signed by all parties hereto.

11. ENTIRE AGREEMENT. This Agreement, together with its exhibit, constitutes the entire understanding and agreement of the parties with respect to its subject matter, and effective upon the execution of this Agreement by the respective parties hereof and thereto, any and all prior agreements, understandings, or representations with respect to this subject matter are hereby terminated and canceled in their entirety and are of no further force and effect.

12. WAIVER. No waiver by any party hereto of a breach of any provision of this Agreement shall constitute a waiver of any preceding or succeeding breach of the same or any other provision hereof.

13. ASSIGNMENT. This Agreement shall inure to the benefit and shall be binding upon the parties and their respective successors and assigns. No assignment of this Agreement or any party's rights, interests, or obligations hereunder may be made without the other party's consent, which shall not be unreasonably withheld, delayed, or conditioned.

14. SEVERABILITY. If any provision or provisions of this Agreement shall be held by a court of competent jurisdiction to be invalid, illegal, or unenforceable, the validity, legality, and enforceability of the remaining provisions shall in no way be affected or impaired thereby.

15. COUNTERPARTS. This Agreement may be executed in one or more counterparts, all of which taken together shall be deemed one and the same instrument.

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed as of this 11th day of February, 2021.

LG&E and KU Energy LLC

By: KtWBlake
Name: KENT W. BLAKE
Title: CFO

LG&E and KU Services Company

By: KtWBlake
Name: KENT W. BLAKE
Title: CFO

Kentucky Utilities Company

By: KtWBlake
Name: KENT W. BLAKE
Title: CFO

Louisville Gas and Electric Company

By: KtWBlake
Name: KENT W. BLAKE
Title: CFO

[LKE Signature Page to Amended and Restated Utility Services Agreement]

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed as of this 11th day of FEBRUARY, 2021.

PPL Corporation

By:______________________
Name: Tadd J. Henninger
Title: Vice President – Finance and Treasurer

PPL Capital Funding, Inc.

By:______________________
Name: Tadd J. Henninger
Title: Vice President and Treasurer

PPL Services Corporation

By:______________________
Name: Tadd J. Henninger
Title: Vice President – Finance and Treasurer

PPL EU Services Corporation

By:______________________
Name: Tadd J. Henninger
Title: Vice President and Treasurer

[PPL Signature Page to Amended and Restated Utility Services Agreement]

AMENDMENT NO. 2
TO 2011 UTILITY MONEY POOL AGREEMENT

This **AMENDMENT NO. 2** dated as of May 18, 2020 (this "Amendment") amends the 2011 Utility Money Pool Agreement (the "Agreement") dated December 1, 2011, by and between LG&E and KU Energy LLC, LG&E and KU Services Company, Louisville Gas and Electric Company and Kentucky Utilities Company (each a "Party" and collectively, the "Parties").

WITNESSETH:

WHEREAS, the Parties desire to amend certain provisions of the Agreement to reflect appropriate market conditions.

NOW, THEREFORE, in consideration of the promises and the mutual agreements and covenants contained herein, the Parties hereto agree as follows:

1. "Section 1.05 Interest" is hereby deleted and replaced, in its entirety, with the following:

> "Section 1.05 Interest. The daily outstanding balance of all loans to any Utility Subsidiary during a calendar month shall accrue interest at a rate equal to the lower of 1) the rate for a one month Euro-dollar loan under the revolving credit facility of such Utility Subsidiary using LIBOR as of the last day of the prior calendar month as reported by the *Wall Street Journal*; or 2) the one month rate of other short-term borrowings available to the Parties, including third party or affiliate loans using LIBOR as of the last day of the prior calendar month as reported by the *Wall Street Journal*; or 3) the sum of (a) such daily rate for 30-day A2/P2 rated non-financial commercial paper programs as published by the Federal Reserve System of the United States under the symbol CP/RATES/RIFSPPNA2P2D30_N.B. (or substantially equivalent rate, if such rate is discontinued or modified) on the last business day of the prior calendar month and (b) five (5) basis points. LG&E and KU Services Company will not charge interest or fees for managing the Utility Money Pool."

IN WITNESS WHEREOF, this Amendment has been executed and delivered by a duly authorized officer of each Party hereto, as of the date above first written.

LG&E AND KU ENERGY LLC
LG&E AND KU SERVICES COMPANY

By:____________________________
John R. Crockett III, General Counsel, Chief Compliance Officer and Corporate Secretary

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

By:____________________________
Daniel K. Arbough, Treasurer

Louisville Gas and Electric Company's Annual Report of Nonregulated Activities

Required by 807 KAR 5:080 Calendar Year 2020

Filed with the Kentucky Public Service Commission on March 31, 2021

Index to the Annual Reporting of
Louisville Gas and Electric Company - Calendar Year 2020

DATA REQUIREMENT	SOURCE	REPORT
Description of Change to Cost Allocation Manual	807 KAR 5:080, Section 2 (1)(a)	For many years, LG&E has followed its LG&E and KU Services Company Cost Allocation Manual for affiliate cost allocations. LG&E began utilizing an updated Cost Allocation Manual, effective January 1, 2020. *See* Case No. 2020-00350, Application Filing Requirement Tab 51. LG&E uses the fully-distributed cost method pursuant to KRS 278.2203(2)(a). The costs associated with the non-regulated activities described in this Report are directly assigned and are consistent with the requirements in the Cost Allocation Manual.
Nonregulated activities	807 KAR 5:080, Section 2 (1)(b)	Exhibit A
List of nonregulated affiliates	807 KAR 5:080, Section 2 (1)(c)	Exhibit B
Copy of service agreements	807 KAR 5:080, Section 2 (2)	Exhibit C

Exhibit A

A report on the utility's incidental nonregulated activity that describes the activity and provides justification for reporting the nonregulated activity as an incidental nonregulated activity, including:

1. *Revenue per year or percentage of total revenue per year of the activity reported as an incidental nonregulated activity;*

2. *A calculation demonstrating the manner in which the affected utility has determined the percentage of revenue set forth in subparagraph 1 of this paragraph;*

3. *A full explanation as to why the activity reported as an incidental nonregulated activity is reasonably related to the affected utility's regulated services*

EXHIBIT A

NONREGULATED ACTIVITIES OF LOUISVILLE GAS AND ELECTRIC COMPANY
For Year Ended December 31, 2020

Activity	Revenues
Industrial Coal Services[1] Service offered to a large industrial customer who, due to unique locational circumstances, needs service from LG&E's coal transportation and unloading facilities.	$1,929,638
Trimble County 1 Working Capital Charges As a result of the Commission disallowance of 25% of both the cost and asset of Trimble County Unit No. 1[2], this unit is partially owned by Illinois Municipal Electric Agency ("IMEA") and Indiana Municipal Power Agency ("IMPA"). The participation agreements between LG&E and these agencies provide for a working capital charge to be billed at LG&E's cost of capital.	$282,895
Trimble County 1 Service Fee As a result of the Commission disallowance of 25% of both the cost and asset of Trimble County Unit No. 1[3], this unit is partially owned by IMEA, and under the Participation Agreement between LG&E and IMEA, IMEA must pay a monthly service fee.	$777,833
Total 2020 LG&E Nonregulated Revenue	$2,990,366
Total 2020 LG&E Operating Revenue	$1,463,208,605
Nonregulated % of Total Revenue	0.20437%

[1]

Gross Industrial Coal Services	$ 1,929,638
Coal Services Cost of Sales	(1,494,471)
Net Industrial Coal Services	$ 435,167

[2] In the Matter of: A Formal Review Of The Current Status of Trimble County Unit No. 1, Case No. 9934 Order (July 1, 1988) and Order, p.6 (April 20, 1989)("LG&E retains control over the 25 percent of Trimble County disallowed to use as its management sees fit.")

[3] *Id*.

Exhibit B

The list below shows only nonregulated (i.e. not regulated by the KPSC) affiliates of Kentucky Utilities Company ("KU") directly or indirectly owned by PPL Corporation, where such indirect or direct ownership exceeds 10%.

Certain entities shown are also regulated, in part, by other state utility commissions (PPL Electric Utilities Corporation ("PPL EU")), by the Federal Energy Regulatory Commission (PPL EU and Electric Energy, Inc.), or by Ofgem in the United Kingdom (the four Western Power Distribution electricity distribution companies).

Name	Nature of Business
2711171 Ontario Inc.	Holding company (minority interest)
Aztec Insurance Limited	Captive insurance company located in Guernsey
Bulloch County GA S1, LLC	Solar energy company
Central Networks Trustees Limited	Dormant company
CEP Commerce, LLC	Holding company
CEP Lending, Inc.	Finance company for PPL Corporation and its affiliates
CEP Reserves, Inc.	Finance company for PPL Corporation and its affiliates
Chambersburg Solar Center, LLC	Solar energy company
Demand Power Group Inc.	Canadian renewable energy company (minority interest)
DHA, LLC	Community housing lending fund in Louisville (minority interest)
East Brunswick Solar LLC	Solar energy company
Electralink Limited	Data Transfer Service operator in connection with the operation of the competitive electricity supply market in England, Scotland and Wales
Electric Energy, Inc.	Illinois power plant owner/operator and wholesale power seller (minority interest)
Envista Energy LP	Canadian renewable energy company
FCD LLC	Lessee of river coal dock in Western Kentucky
Franklin County GA S1, LLC	Solar energy company
Gemserv Limited	Consulting services provider serving utility and other markets in the UK and Europe
Greene County GA S1, LLC	Solar energy company
Hyder Limited	In liquidation
Hyder Profit Sharing Trustee Limited	Dormant company
Infralec 1992 Pension Trustee Limited	Dormant company
Jackson Solar LLC	Solar energy company
Joppa & Eastern Railroad Company	Owner of certain spur railroad rights in Illinois (minority interest)
Kelston Properties 2 Limited	Owner a single property that is leased to a major supermarket group
Lexington Utilities Company	Dormant company
LG&E and KU Capital LLC	Holding company
LG&E and KU Energy LLC	Holding company
LG&E and KU Foundation Inc.	Charitable foundation
LG&E and KU Hydro I LLC	Dormant company
LG&E and KU Services Company	Centralized service company providing administrative, managerial and technical goods and services to affiliates
LG&E Energy Inc.	Dormant company
Lowndes County GA S1, LLC	Solar energy company
Lowndes County GA S2, LLC	Solar energy company
Mainely Solar, LLC	Solar energy company (majority interest)
Meriwether County GA S1, LLC	Solar energy company
Met-South, Inc.	Operator/marketer with respect to coal combustion byproducts and facilities (minority interest)
Meter Operator Services Limited	Dormant company
Meter Reading Services Limited	Dormant company
Midwest Electric Power, Inc.	Illinois power plant owner/operator and wholesale power seller (minority interest)
Murray County GA S1, LLC	Solar energy company
PMDC International Holdings, Inc.	Holding company
PP&L Residual Corporation	Dormant company
PPL (Barbados) SRL	Holding and finance company
PPL Atlantic Holdings, LLC	Holding Company

PPL Canada GP ULC	Canadian company serving as general partner in Canadian partnership
PPL Canada Holdings Inc.	Holding company
PPL Capital Funding, Inc.	Financing company for PPL Corporation and its affiliates, other than PPL Electric Utilities Corporation
PPL Corporation	Holding company
PPL Distributed Energy Resources, LLC	Renewable energy company
PPL Electric Utilities Corporation	Transmission and distribution company regulated by the Pennsylvania Public Utility Commission
PPL Energy Holdings, LLC	Holding company
PPL Energy Funding Corporation	Holding company
PPL Energy Resources, LLC	Holding company
PPL EU Services Corporation	Services provider for PPL Electric Utilities Corporation and its affiliates
PPL Foundation	Charitable foundation
PPL Global, LLC	Holding company
PPL Island Limited	Finance company for WPD affiliates
PPL Midlands Limited	Property investment company
PPL Power Insurance Ltd.	Captive insurance company located in Bermuda
PPL Renewables, LLC	Holding company and developer of renewable projects
PPL Safari Holdings, LLC	Holding Company
PPL Services Corporation	Services provider for PPL Corporation and its affiliates
PPL Strategic Development, LLC	Engages in development, acquisition and divestiture activities for affiliates
PPL Subsidiary Holdings, LLC	Holding company
PPL Technology Ventures, LLC	Holding and finance company
PPL TransLink, Inc.	Dormant company
PPL UK Holdings, LLC	Holding company
PPL UK Investments Limited	Holding company
PPL UK Resources Limited	Holding and finance company for WPD affiliates
PPL UK Distribution Holdings Limited	Dormant company
PPL WEM Limited	Holding and finance company
PPL WPD Investments Limited	Holding company
PPL WPD Limited	Holding company
Putnam County GA S1, LLC	Solar energy company
Safari Baboon, LLC	Solar energy company
Safari Chimpanzee, LLC	Solar energy company
Safari Donkey, LLC	Solar energy company
Safari Elephant, LLC	Solar energy company
Safari Energy Construction, LLC	Solar energy company
Safari Energy Georgia 1-2019, LLC	Solar energy company
Safari Energy Georgia 2-2019, LLC	Solar energy company
Safari Energy Georgia 3-2019, LLC	Solar energy company
Safari Energy Georgia 4-2019, LLC	Solar energy company
Safari Energy Georgia 5-2020, LLC	Solar energy company
Safari Energy Georgia 6-2020, LLC	Solar energy company
Safari Energy Georgia 7-2020, LLC	Solar energy company
Safari Energy Georgia 8-2020, LLC	Solar energy company
Safari Energy Illinois 1-2019, LLC	Solar energy company
Safari Energy Illinois 2-2020, LLC	Solar energy company
Safari Energy Investments 1, LLC	Solar energy company
Safari Energy Massachusetts 1-2019, LLC	Solar energy company
Safari Energy Massachusetts 2-2019, LLC	Solar energy company
Safari Energy Massachusetts 3-2019, LLC	Solar energy company
Safari Energy Massachusetts 4-2020, LLC	Solar energy company
Safari Energy Massachusetts 5-2020, LLC	Solar energy company
Safari Energy New York 1-2020, LLC	Solar energy company
Safari Energy Ohio 1-2019, LLC	Solar energy company
Safari Energy Rhode Island 1-2020, LLC	Solar energy company
Safari Energy Rhode Island 2-2020, LLC	Solar energy company
Safari Energy, LLC	Solar energy company
Safari Kangaroo, LLC	Solar energy company
Safari Loris, LLC	Solar energy company
Safari Orangutan, LLC	Solar energy company
Safari Viper, .LLC	Solar energy company
Safari Zebra, LLC	Solar energy company
Sebago Solar, LLC	Solar energy company (majority interest)
Shane Solar, LLC	Solar energy company (majority interest)
Sheet Road Management Company Limited	Manages and controls surface water drainage assets (majority interest)

Solar Star Energy Center, LLC	Solar energy company
Solar Star Meridian Park, LLC	Solar energy company
South Wales Electricity Share Scheme Trustees Limited	Dormant company
South Western Helicopters Limited	Provider of electricity power line inspection services to regional electricity companies
Terrell County GA S1, LLC	Solar energy company
Troup County GA S1, LLC	Solar energy company
Ware County GA S1, LLC	Solar energy company
Ware County GA S2, LLC	Solar energy company
Wesleyan Solar Array, LLC	Solar energy company
Western Kentucky Energy Corp.	Dormant company
Western Power Distribution (East Midlands) plc	Electricity distribution company in the U.K.
Western Power Distribution (West Midlands) plc	Electricity distribution company in the U.K.
Western Power Distribution (South Wales) plc	Electricity distribution company in the U.K.
Western Power Distribution (South West) plc	Electricity distribution company in the U.K.
Western Power Distribution Investments Limited	Holding company includes a portfolio of properties
Western Power Distribution plc	Holding and finance company for WPD affiliates
Western Power Generation Limited	Electricity generating company operating in the U.K.
Western Power Pension Trustee Limited	Dormant company
Wilkinson County GA S1, LLC	Solar energy company
WPD Distribution Network Holdings Limited	Holding and finance company
WPD Foundation	Charitable foundation
WPD Investment Holdings Limited	Holding company
WPD Limited	Dormant company
WPD Limited (Guernsey)	Property investment company located in Guernsey
WPD Midlands Networks Contracting Limited	Dormant company
WPD Property Investments Limited	Property management company
WPD Share Scheme Trustees Limited	Dormant company
WPD Smart Metering Limited	Operator of electricity metering business
WPD Telecoms Limited	Fiber optic cable services company
WW Share Schemes Trustees Limited	Dormant company
Wyman Hill Solar, LLC	Solar energy company (majority interest)

Exhibit C

A copy of each service agreement existing on the effective date of KRS 278.2201 through 278.2219 and remaining in effect shall be filed as an attachment to the annual report required by this subsection. After the initial filing, an affected utility shall file only new or amended service agreements with the annual report.

See attached.

AMENDED AND RESTATED UTILITY SERVICES AGREEMENT

This Amended and Restated Utility Services Agreement (this "Agreement") is entered into as of the 15th day of December, 2020, by and between Kentucky Utilities Company ("KU-ODP"), a public utility organized under Virginia and Kentucky law and doing business in Virginia as "Old Dominion Power Company"; Louisville Gas and Electric Company ("LG&E"), a public utility organized under Kentucky law; LG&E and KU Energy LLC ("LKE"), a Kentucky limited liability company; LG&E and KU Services Company ("LK Services"), a Kentucky corporation; PPL Corporation ("PPL"), a Pennsylvania corporation; PPL Capital Funding, Inc. ("PPL Capital"), a Delaware corporation; PPL Services Corporation ("PPL Services"), a Delaware corporation; and PPL EU Services Corporation ("PPLEU Services"), a Delaware corporation (collectively, the "Affiliates").

WHEREAS, KU-ODP, LG&E, and LK Services are direct, wholly owned subsidiaries of LKE, and PPL Capital, PPL Services, and PPLEU Services are direct, wholly owned subsidiaries of PPL, the parent of LKE;

WHEREAS, LK Services has been formed for the purpose of providing goods and administrative, management, and other services to subsidiaries and affiliates of LKE, including the utility operations of KU/ODP and LG&E

WHEREAS, PPL Services and PPLEU Services (collectively, the "Pennsylvania Service Companies") have been formed for the purpose of providing goods and administrative, management and other services to subsidiaries and affiliates of PPL;

WHEREAS, PPL Capital has been formed for the purpose of providing financing for the operations of PPL and its Affiliates;

WHEREAS, KU-ODP is a public service company as that term is used in Chapter 4 of Title 56 of the Code of Virginia and a public service company as that term is used in other applicable portions of Title 56 of the Code of Virginia as administered by the State Corporation Commission ("Commission");

WHEREAS, the Affiliates are parties to an Amended and Restated Utility Services Agreement approved by the Commission in Case No. PUE-2015-00126 by Order Granting Authority dated February 24, 2016, and further approved by the Commission in Case No. PUR-2020-00256 by Order Granting Approval dated December 15, 2020.

WHEREAS, KU-ODP and LG&E believe that it is in their interest to provide for an arrangement whereby they may, from time to time and at their option, agree to purchase such goods and administrative, management, and other services, including third-party goods and services, from LK Services, LKE, PPL, PPL Services, and PPLEU Services;

WHEREAS, KU-ODP and LG&E, believe that is it is in their interest to provide telecommunication services, use of facility space, and other services to LK Services at their election;

WHEREAS, KU-ODP and LG&E desire an arrangement whereby PPL Capital may procure letters of credit for KU-ODP LG&E, or the other Affiliates;

WHEREAS, the procurement of such goods and services, at the sole election of KU-ODP and LG&E, may result in purchasing and operational efficiencies, or is otherwise administratively necessary, and is in the public interest and the interest of KU-ODP and LG&E;

WHEREAS, because KU-ODP and LG&E engage in the joint planning and operation of their respective electrical systems as an integrated generation and transmission system and mutual distribution systems, it is in the public interest for KU-ODP and LG&E to establish an arrangement whereby they may from time to time and at their option, agree to provide or receive services, construction, or goods on an emergency basis or otherwise to or from each other at cost less depreciation, and provide or receive interests in land from one another at cost;

WHEREAS, KU-ODP and LG&E desire an arrangement whereby LK Services may act as payment and billing agent for them; and

NOW, THEREFORE, in consideration of the mutual covenants contained herein and other valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, intending to be legally bound, hereby agree as follows:

1. GOODS AND SERVICES. LKE, LK Services, PPL, PPL Services, and PPLEU Services will supply certain goods and administrative, management, or other services to KU-ODP and LG&E similar to those supplied to other subsidiaries or affiliates of LKE and PPL. Such services and goods are and will be provided to KU-ODP and LG&E only at their request. LKE, LK Services, PPL, PPL Services, and PPLEU Services will procure certain goods and services needed by KU-ODP and LG&E from third-party vendors. Such third-party goods and services will be provided to KU-ODP and LG&E only at the request of KU-ODP and LG&E. LKE, LK Services, PPL, PPL Capital, PPL Services, and PPLEU Services will invoice KU-ODP and LG&E or their payment and billing agent, LK Services, at cost, for KU-ODP's or LG&E's portion of the costs of purchases of goods and services. KU-ODP and LG&E may supply telecommunication services, use of facility space, and other services to LK Services at the election of KU-ODP or LG&E. KU-ODP and LG&E will invoice LK Services, at their fully distributed cost.

2. LETTER OF CREDIT. PPL Capital will procure letters of credit for KU-ODP and LG&E. Such transactions will be invoiced at cost to the respective party or its payment and billing agent, LK Services.

3. PERSONNEL. LK Services and the Pennsylvania Service Companies will provide KU/ODP and LG&E such goods and services by utilizing the services of their, or their affiliates', executives, accountants, financial advisers, technical advisers, attorneys, and other persons with the necessary qualifications.

If necessary, LKE, LK Services, PPL, and Pennsylvania Service Companies, after consultation with and consent by KU-ODP and LG&E, may also arrange for the services of nonaffiliated experts, consultants, and attorneys in connection with the performance of any of the services supplied under this Agreement.

4. TRANSACTIONS BETWEEN KU-ODP AND LG&E. KU-ODP and LG&E may, from time to time, provide or receive such services, to or from each other, for the construction, ownership, operation or maintenance of their generation facilities and their respective distribution and transmission systems, as well as for retail business services. Such transactions will be invoiced at fully allocated cost and will occur only as reasonably required when KU-ODP and LG&E believe in good faith that such transactions will be to the advantage of KU-ODP and LG&E. KU-ODP and LG&E may, from time to time, provide or receive, at not more than cost less depreciation, goods purchased by either KU-ODP or LG&E. KU-ODP and LG&E may, from time to time, provide or receive interests in land from one another in the ordinary course of business for the construction, ownership, operation, or maintenance of their generation facilities and their respective distribution and transmission systems. Such transactions will be invoiced at cost to the respective party or its payment and billing agent, LK Services.

5. COMPENSATION AND ALLOCATION. As and to the extent required by law, LKE, LK Services, PPL, and the PPL Service Companies provide and will provide such goods and services at fully allocated cost in accordance with the requirements of the Cost Allocation Manual attached as Exhibit A. KU-ODP and LG&E, at their election, will provide services to LK Services at fully distributed cost.

6. TERMINATION AND MODIFICATION. Any party to this Agreement may terminate this Agreement, with respect to itself, by providing 60 days written notice of such termination to the remaining parties.

This Agreement is subject to termination or modification at any time to the extent its performance may conflict with the provisions of the Federal Power Act or the Public Utility Holding Company Act of 2005, as amended, or with any rule, regulation or order of the Federal Energy Regulatory Commission adopted before or after the making of this Agreement. This Agreement shall be subject to the approval of any state commission or other state regulatory body whose approval is, by the laws of said state, a legal prerequisite to the execution and delivery or the performance of this Agreement.

The authorization for this Agreement shall expire at the conclusion of five years beginning on the date this Agreement is given final approval by the Virginia State Corporation Commission, unless the Virginia State Corporation Commission extends its authorization.

7. BILLING AND PAYMENT. Unless otherwise agreed, payment for services provided by any of the parties to this Agreement shall be by making remittance of the amount billed or by making appropriate accounting entries on the books of the appropriate parties. Billing will be made on a monthly basis, with the bill to be rendered by the 25th of the month, and remittance or accounting entries completed within 30 days of billing. Any amount remaining unpaid after 30 days following receipt of the bill shall bear interest thereon from the date of the bill at annual rate of A1/P1 30-day Commercial Paper. At KU-ODP's and LG&E's request, LK Services may act as their payment and billing agent. Payment and billing services, include, but are not limited to, sending or receiving invoices, receiving or disbursing payment, and making appropriate accounting entries.

8. NOTICE. Where written notice is required by this Agreement, all notices, consents, certificates, or other communications hereunder shall be in writing and shall be deemed given when mailed by United States registered or certified mail, postage prepaid, return receipt requested, addressed as follows:

To KU-ODP:
One Quality Street
Lexington, Kentucky 40507
Attn: Corporate Secretary

To LG&E:
220 West Main Street
Louisville, Kentucky 40202
Attn: Corporate Secretary

To LKE:
220 West Main Street
Louisville, Kentucky 40202
Attn: Corporate Secretary

To LK Services:
220 West Main Street
Louisville, Kentucky 40202
Attn: Corporate Secretary

To PPL:
2 North Ninth Street
Allentown, Pennsylvania 18101
Attn: Corporate Secretary

To PPL Capital:
2 North Ninth Street
Allentown, Pennsylvania 18101
Attn: Corporate Secretary

To PPL Services:
2 North Ninth Street
Allentown, Pennsylvania 18101
Attn: Corporate Secretary

To PPLEU Services:
2 North Ninth Street
Allentown, Pennsylvania 18101
Attn: Corporate Secretary

9. GOVERNING LAW. This Agreement shall be governed by and construed in accordance with the laws of the Commonwealth of Kentucky, without regard to its conflict of laws provisions.

10. MODIFICATION. No amendment, change, or modification of this Agreement shall be valid unless made in writing and signed by all parties hereto.

11. ENTIRE AGREEMENT. This Agreement, together with its exhibit, constitutes the entire understanding and agreement of the parties with respect to its subject matter, and effective upon the execution of this Agreement by the respective parties hereof and thereto, any and all prior agreements, understandings, or representations with respect to this subject matter are hereby terminated and canceled in their entirety and are of no further force and effect.

12. WAIVER. No waiver by any party hereto of a breach of any provision of this Agreement shall constitute a waiver of any preceding or succeeding breach of the same or any other provision hereof.

13. ASSIGNMENT. This Agreement shall inure to the benefit and shall be binding upon the parties and their respective successors and assigns. No assignment of this Agreement or any party's rights, interests, or obligations hereunder may be made without the other party's consent, which shall not be unreasonably withheld, delayed, or conditioned.

14. SEVERABILITY. If any provision or provisions of this Agreement shall be held by a court of competent jurisdiction to be invalid, illegal, or unenforceable, the validity, legality, and enforceability of the remaining provisions shall in no way be affected or impaired thereby.

15. COUNTERPARTS. This Agreement may be executed in one or more counterparts, all of which taken together shall be deemed one and the same instrument.

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed as of this 11th day of February, 2021.

LG&E and KU Energy LLC

By: Kent W Blake
Name: KENT W. BLAKE
Title: CFO

LG&E and KU Services Company

By: Kent W Blake
Name: KENT W. BLAKE
Title: CFO

Kentucky Utilities Company

By: Kent W Blake
Name: KENT W. BLAKE
Title: CFO

Louisville Gas and Electric Company

By: Kent W Blake
Name: KENT W. BLAKE
Title: CFO

[LKE Signature Page to Amended and Restated Utility Services Agreement]

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed as of this 11th day of FEBRUARY, 2021.

PPL Corporation

By:______________________
Name: Tadd J. Henninger
Title: Vice President – Finance and Treasurer

PPL Capital Funding, Inc.

By:______________________
Name: Tadd J. Henninger
Title: Vice President and Treasurer

PPL Services Corporation

By:______________________
Name: Tadd J. Henninger
Title: Vice President – Finance and Treasurer

PPL EU Services Corporation

By:______________________
Name: Tadd J. Henninger
Title: Vice President and Treasurer

[PPL Signature Page to Amended and Restated Utility Services Agreement]

AMENDMENT NO. 2
TO 2011 UTILITY MONEY POOL AGREEMENT

This **AMENDMENT NO. 2** dated as of May 18, 2020 (this "Amendment") amends the 2011 Utility Money Pool Agreement (the "Agreement") dated December 1, 2011, by and between LG&E and KU Energy LLC, LG&E and KU Services Company, Louisville Gas and Electric Company and Kentucky Utilities Company (each a "Party" and collectively, the "Parties").

WITNESSETH:

WHEREAS, the Parties desire to amend certain provisions of the Agreement to reflect appropriate market conditions.

NOW, THEREFORE, in consideration of the promises and the mutual agreements and covenants contained herein, the Parties hereto agree as follows:

1. "Section 1.05 Interest" is hereby deleted and replaced, in its entirety, with the following:

> "Section 1.05 Interest. The daily outstanding balance of all loans to any Utility Subsidiary during a calendar month shall accrue interest at a rate equal to the lower of 1) the rate for a one month Euro-dollar loan under the revolving credit facility of such Utility Subsidiary using LIBOR as of the last day of the prior calendar month as reported by the *Wall Street Journal*; or 2) the one month rate of other short-term borrowings available to the Parties, including third party or affiliate loans using LIBOR as of the last day of the prior calendar month as reported by the *Wall Street Journal*; or 3) the sum of (a) such daily rate for 30-day A2/P2 rated non-financial commercial paper programs as published by the Federal Reserve System of the United States under the symbol CP/RATES/RIFSPPNA2P2D30_N.B. (or substantially equivalent rate, if such rate is discontinued or modified) on the last business day of the prior calendar month and (b) five (5) basis points. LG&E and KU Services Company will not charge interest or fees for managing the Utility Money Pool."

IN WITNESS WHEREOF, this Amendment has been executed and delivered by a duly authorized officer of each Party hereto, as of the date above first written.

LG&E AND KU ENERGY LLC
LG&E AND KU SERVICES COMPANY

By: ______________________________
John R. Crockett III, General Counsel, Chief Compliance Officer and Corporate Secretary

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

By: ______________________________
Daniel K. Arbough, Treasurer

Rebuttal Exhibit CMG-3 is being provided in a separate file in Excel format.

Rebuttal Exhibit
CMG-4 is
being provided in a
separate file in Excel
format.

Rebuttal Exhibit
CMG-5 is
being provided in a
separate file in Excel
format.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) Approval Of Tariffs And Riders; (3) Approval Of Accounting Practices To Establish Regulatory Assets And Liabilities; (4) Approval of A Certificate of Public Convenience And Necessity; And (5) All Other Required Approvals And Relief	)))))))	Case No. 2020-00174

REBUTTAL TESTIMONY OF

HEATHER M. WHITNEY

ON BEHALF OF KENTUCKY POWER COMPANY

REBUTTAL TESTIMONY OF
HEATHER M. WHITNEY ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2020-00174

TABLE OF CONTENTS

EXHIBITS

EXHIBIT	DESCRIPTION
EXHIBIT HMW-R1	June 2017 Pension Plan Cash Contribution
EXHIBIT HMW-R2	September 2020 Pension Plan Cash Contribution
EXHIBIT HMW-R3	Rollforward of Prepaid Pension and OPEB Asset Balances and Computation of Related Cost of Service Reduction

**REBUTTAL TESTIMONY OF
HEATHER M. WHITNEY ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND PRESENT POSITION.

A. My name is Heather M. Whitney. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation ("AEPSC") as a Director in Regulatory Accounting Services. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power" or the "Company").

Q. ARE YOU THE SAME HEATHER M. WHITNEY WHO OFFERED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to respond to the proposed adjustment presented in the prepared Direct Testimony of Attorney General of the Commonwealth of Kentucky and Kentucky Industrial Utility Customers, Inc. ("AG/KIUC") Witness Lane Kollen to remove prepaid pension and prepaid other postretirement employee benefit ("OPEB") assets from rate base.

I support the inclusion of the prepaid pension and prepaid OPEB assets in rate base.[1] These are cash assets financed by the Company and benefit customers through substantially reduced costs. The Company's accounting is proper under generally accepted accounting principles ("GAAP"), and has received a clean opinion from two separate external auditors. Moreover, if the Commission removes the pension and OPEB assets from rate base and requires the "return on" component of the revenue requirement to be computed using rate base instead of capitalization, then test year cost of service expense must be increased to remove the $3.7 million benefit (lower expense) resulting from these additional contributions.

Q. ARE YOU SPONSORING ANY REBUTTAL EXHIBITS OR SCHEDULES?

A. Yes, I am sponsoring the following exhibits:

- Exhibit HMW-R1 – June 2017 Pension Plan Cash Contribution
- Exhibit HMW-R2 – September 2020 Pension Plan Cash Contribution
- Exhibit HMW-R3 – Rollforward of Prepaid Pension and OPEB Asset Balances and Computation of Related Cost of Service Reduction

[1] The Prepaid Pension balance as of February 28, 2017 was included in Total Rate Base authorized in Case No. 2017-00179. Prepaid Pension and OPEB balances as of February 28, 2017 were reflected in Total Capitalization authorized in Case No. 2017-00179.

III. PREPAID PENSION AND OPEB ASSETS IN RATE BASE

Q. DOES AG/KIUC WITNESS KOLLEN TAKE EXCEPTION TO THE COMPANY'S INCLUSION OF PREPAID PENSION AND OPEB ASSETS IN RATE BASE?

A. Yes. AG/KIUC Witness Kollen recommends that the Commission reject the Company's request to include the prepaid pension and OPEB assets in rate base. Mr. Kollen states that the effects of his recommendation, if approved, would be to reduce rate base by $44.206 million ($44.879 million total Company) for the prepaid pension asset and $19.872 million ($20.175 million total Company) for the prepaid OPEB asset. According to Mr. Kollen, the effect of reducing rate base for these amounts is a reduction of $5.204 million in the base revenue requirement, if the "return on" component of the revenue requirement is computed using rate base instead of capitalization. Company Witness Vaughan's rebuttal testimony supports the Company's continued use of capitalization to compute the "return on" component of the revenue requirement.

Q. PLEASE SUMMARIZE THE REASONS GIVEN BY AG/KIUC WITNESS KOLLEN IN SUPPORT OF HIS RECOMMENDATION TO EXCLUDE THE PREPAID PENSION AND OPEB ASSETS FROM RATE BASE.

A. Mr. Kollen provides the following arguments and assertions in support of his position to exclude the prepaid pension and OPEB assets from rate base:

1. "…the prepaid pension asset and prepaid OPEB asset are not cash assets and should not be included in rate base";[2]

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[2] Direct Testimony of Lane Kollen at 13.

2. "…there is no prepaid pension asset and there is no prepaid OPEB asset unless you ignore the negative amounts in accounts 1650014 and 1650037, which is what the Company did in its calculation of rate base";[3]

3. "…there is no financing requirement associated with those accounts [accounts 1650010, 1650035, 1650014, and 1650037] and no further inquiry is required";[4] and

4. "…the Company's accounting reflected in these four accounts [accounts 1650010, 1650035, 1650014, and 1650037] is not required, defined, or described by GAAP or the FERC USOA. Rather, AEP itself has uniquely defined these accounts for use by its operating utilities within its accounting system for recordkeeping purposes and, as is apparent in multiple rate proceedings in multiple jurisdictions, to assist the operating companies in their attempts to increase rate base by including only the positive amounts in accounts 1650010 and 1650035 in rate base."[5]

Q. DO YOU AGREE WITH AG/KIUC WITNESS KOLLEN'S RECOMMENDATION TO EXCLUDE THE PREPAID PENSION AND OPEB ASSETS FROM RATE BASE?

A. No, I disagree with the AG/KIUC's recommendation and each of the reasons given in support of AG/KIUC Witness Kollen's position. I will address each of the statements referenced above as well as others from AG/KIUC Witness Kollen's testimony and demonstrate that these arguments and assertions are erroneous and/or baseless.

Q. WHAT SUPPORT DOES AG/KIUC WITNESS KOLLEN PROVIDE FOR HIS CLAIM THAT "…THE PREPAID PENSION ASSET AND PREPAID OPEB ASSET ARE NOT CASH ASSETS…"?

A. Mr. Kollen's support for this assertion is not clear to me, but seems to be based on his incorrect interpretation of amounts recorded in the Company's general ledger, despite

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[3] *Id*. at 18.
[4] *Id*. at 21.
[5] *Id*. at 19.

the Company's response to AG/KIUC 2-17. He erroneously deduces that, "The amounts in the four account 165 accounts net to $0, so there is no financing requirement associated with those accounts…," leaving only balances in accounts he refers to as regulatory assets which are, "merely accounting entries that have not been financed."[6] Mr. Kollen's position hinges on a failure to acknowledge that the Company has, in fact, made cash contributions to the pension and OPEB plans in excess of cost, as well as a misinterpretation of a non-cash reclass made for financial reporting purposes under Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 715, Compensation - Retirement Benefits ("Non-Cash ASC 715 Reclass"), supplied in the Company's response to AG/KIUC 2-17.

Q. CAN YOU PLEASE EXPLAIN THE COMPANY'S RESPONSE TO AG/KIUC 2-17 AND PROPERLY DISTINGUISH PENSION AND OPEB CASH PREPAYMENT BALANCES FROM THE NON-CASH ASC 715 RECLASS RECORDED USING A BALANCED, NET $0, ENTRY?

A. Yes. Below, I have aligned the table provided in response to subpart a. of AG/KIUC 2-17 and presented in Mr. Kollen's testimony[7] with the written response to subparts c. and d. of AG/KIUC 2-17. Lines 1 and 9 contain the cash prepayment balances. Lines 2 – 7 contain the Non-Cash ASC 715 Reclasses, which balance to a net $0 amount as shown in Line 8 and expected under accrual, double-entry accounting[8].

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[6] *Id.* at 21.

[7] Direct Testimony of Lane Kollen at 20.

[8] FASB Statement of Financial Accounting Concepts No. 6, Paragraphs 20 and 21, ***Interrelation of Elements – Articulation***, supports the expectation of a balanced entry when applying accrual, double-entry accounting. Specifically, Paragraph 21 provides, "*…an increase (decrease) in an asset cannot occur without a corresponding decrease (increase) in another asset or a corresponding increase (decrease) in a liability or equity (net assets).*"

AG-KIUC 2-17, Subpart a.
Kentucky Power Company
Pension and OPEB Balances as of December 31, 2019

Line No.	Account	Description	Pension	OPEB	Subtotal Tie Out	Cross Reference: AG-KIUC 2-17, Subparts c. and d.	Other References
1	1650010/ 1650035	Prepayment - Contributions	$45,500,106	$19,143,276	A	"The balances in Account 1650010 and 1650035 reflect the Companies' **cumulative cash contributions** in excess of cumulative pension and OPEB cost."	Exhibit HMW-R1 Exhibit HMW-R2 Exhibit HMW-R3
2	1650014/ 1650037	ASC 715 Prepayment Reclass	(45,500,106)	(19,143,276)	B, C	"There are also **non-cash ASC 715 accrual adjustment balances** recorded in Accounts 1290000, 1290001, 1290002, 1290003, 1650014, 1650037, 1823165, 1823166, 2190006, 2190007, 1900010, 1900011, 2283006 and 2283016 that result from entries required by ASC 715 **to separate the calculated prepayment** into two separate components. The **first component is the funded status** and **second component is other comprehensive income (or a regulatory asset)** for gains and losses that have not yet been recognized as components of net periodic benefit cost."	Total Non-Cash ASC 715 Reclass
3	1290000/ 1290001	ASC 715 Trust Funded Positions (Assets)	-	23,421,499	B		Reclass Component 1: Funded status
4	2283016/ 2283006	ASC 715 Trust Funded Position (Liabilities)	(1,611,500)	-	B		
5	1823165/ 1823166	ASC 715 - Regulatory Asset	45,940,166	(2,107,133)	B		Reclass Component 2: Other comprehensive income/ regulatory asset
6	1900010/ 1900011	ASC 715 - ADFIT Asset	246,002	(455,929)	B		
7	2190006/ 2190007	ASC – 715 Other Comprehensive Income	925,438	(1,715,161)	B		
8		**Total ASC 715 Entries**	-	-	= ∑ B's	"...The prepaid assets related to pension and OPEB are recorded on the Company's books under FASB ASC 715, Compensation - Retirement Benefits." "...the ASC 715 entries zero out [Sum of B's] leaving the **cash prepayment [A]** that is the Company's cumulative contributions in excess of cumulative pension and OPEB cost, which is included in the Company's calculation of rate base in this proceeding. The **non-cash ASC 715 accounting entries [Sum of B's]** are made for financial reporting purposes and **do not impact the cost of service**."	
9		**Total Prepayment Contributions**	**45,500,106**	**19,143,276**	= A		
10		Total Excluding 165 Accounts	$ 45,500,106	$ 19,143,276	= ∑B's - C	-	

Line 10 in the table above reflects the position of AG/KIUC Witness Kollen, which is based on a misinterpretation of the Non-Cash ASC 715 Reclass, since it results in an unbalanced entry. Mr. Kollen's view is that the Non-Cash ASC 715 Reclass on Line 2 should be isolated and evaluated separately from the remaining elements of the Non-Cash ASC 715 Reclass entry shown in Lines 3 – 7, since the non-cash amounts in Line 2 are recorded to the same FERC account as the cash prepayments shown in Line 1, FERC Account 165. As can be clearly seen, Mr. Kollen's view is erroneous and baseless under the basic accrual accounting concept of balanced journal entries; it is misleading in that Mr. Kollen's departure from a basic accrual accounting concept veils the Company's actual cash prepayment (Line 1) with one unbalanced element of a non-cash reclass entry (Line 2) and then characterize the remaining, unbalanced elements of the non-cash reclass entry (Lines 3 - 7) as ineligible for inclusion in rate base since the non-cash amounts are not financed.

Q. DO YOU HAVE EVIDENCE TO SHOW THAT THE COMPANY'S PREPAID PENSION ASSET RECORDED IN ACCOUNT 1650010 IS, IN FACT, A CASH ASSET?

A. Yes. Page 1 of Exhibit HMW-R1 and Exhibit HMW-R2 shows the payments made by AEP to the Bank of New York in June 2017 and September 2020, respectively, on behalf of the AEP subsidiary companies, including Kentucky Power Company, for the pension plan contributions made since the Company's last base case proceeding in Case No. 2017-00179. Page 2 of Exhibit HMW-R1 and Exhibit HMW-R2 shows Kentucky Power Company's portion of this cash payment allocated to the Kentucky Power Company Distribution, Transmission and Generation functional business units. Page 2 of Exhibit HMW-R1 and Exhibit HMW-R2 also shows that the entry at the time of the pension contribution recorded on Kentucky Power Company's books was a debit to Account 1650010, Prepaid Pension Benefits, and a credit to Account 2340001, Accounts Payable Assoc Co - InterUnit G/L. Kentucky Power Company reimbursed AEP for the pension plan contribution through the AEP Money Pool. Therefore, the Company's prepaid pension and OPEB assets are "cash assets" because they were established based on cash transactions.

Q. WAS THE PROCESS FOR THE COMPANY'S CASH CONTRIBUTIONS TO THE PENSION PLAN PRIOR TO THE TEST YEAR END DATE IN THE COMPANY'S LAST BASE CASE PROCEEDING (CASE NO. 2017-00179) THE SAME AS YOU DESCRIBED ABOVE FOR THE 2017 AND 2020 PENSION PLAN CONTRIBUTIONS?

A. Yes.

Q. HAS THE COMPANY MADE ANY CASH CONTRIBUTIONS TO THE OPEB PLAN SINCE THE TEST YEAR END DATE IN THE COMPANY'S LAST BASE CASE PROCEEDING?

A. No. The prepaid OPEB asset was established on the Company's books in March 2014. Prior to 2014, the Company's OPEB funding policy was to contribute an amount to the OPEB trust fund equal to the other postretirement benefit cost. The Company stopped making OPEB contributions after 2012 when the cost became negative due to changes made to the retiree medical coverage. These changes included the capping of contributions to retiree medical costs thus reducing the Company's future exposure to medical cost inflation. Also, effective for employees hired after December 2013, retiree medical coverage will not be provided.

Q. WAS THE PROCESS FOR THE COMPANY'S CASH CONTRIBUTIONS TO THE OPEB PLAN PRIOR TO 2012 (WHEN THE COST BECAME NEGATIVE DUE TO CHANGES MADE TO RETIREE MEDICAL COVERAGE) THE SAME AS YOU DESCRIBED ABOVE FOR THE 2017 AND 2020 PENSION PLAN CONTRIBUTIONS?

A. Yes.

Q. DOES AG/KIUC WITNESS KOLLEN AGREE THAT CASH ASSETS SHOULD EARN A RETURN THROUGH INCLUSION IN RATE BASE?

A. Yes, it would appear so. Mr. Kollen states that, "If the former [accounts are assets that the Company financed], then they should be included in rate base." He does not clearly convey his definition of "financed"; however, he does indicate that outlay of cash provides evidence of financing and supports inclusion in rate base.[9] As demonstrated in Exhibit HMW-R1 and Exhibit HMW-R2, and as discussed above, the Company's prepaid pension and OPEB assets are cash assets and as such, are reflected Kentucky Power Company's capitalization and are appropriately included in rate base in Kentucky Power Company's cost of service studies.

Q. DO THE COMPANY'S CASH PREPAID PENSION AND OPEB ASSETS PRODUCE A NET BENEFIT TO CUSTOMERS?

A. Yes. Exhibit HMW-R3 rolls the prepaid pension and OPEB asset account balances forward from the Company's last base case proceeding in order to demonstrate that period-end prepaid account balances (Column C) represent cumulative cash contributions (contributions since last base case reflected in Column A) in excess of cumulative pension and OPEB cost (cost since last base case reflected in Column B). In addition, Exhibit HMW-R3 shows the cumulative prepaid pension and OPEB assets have reduced Total Company pension and OPEB cost Kentucky Power Company would otherwise have incurred and recorded on its books by approximately $3.8

[9] Direct Testimony of Lane Kollen at 13. There, Mr. Kollen testifies that, "…the prepaid pension asset and prepaid OPEB asset are not cash assets and should not be included in rate base." Therefore, inversely, cash assets should be included in rate base.

million annually since the Company's last base case proceeding (Exhibit HMW-R3, Line 23). In other words, had the cash contributions not been made to the pension and OPEB plans, the Company's total amount of pension and OPEB cost would have increased by approximately $3.8 million annually. For the Company's test year ended March 31, 2020, approximately $3.7 million in cost savings were included as a reduction in the Company's cost of service (Exhibit HMW-R3, Line 19).

Q. ARE WITNESS KOLLEN'S CLAIMS THAT THE COMPANY IGNORED "…THE NEGATIVE AMOUNTS IN ACCOUNTS 1650014 AND 1650037…IN ITS CALCULATION OF RATE BASE." AND , "THERE IS NO FINANCING REQUIREMENT ASSOCIATED WITH THOSE ACCOUNTS [ACCOUNTS 1650010, 1650035, 1650014, and 1650037]…"ACCURATE?

A. No, as I previously explained, this assertion is both erroneous and baseless under the basic accrual accounting concept of balanced journal entries. In addition, as further explained below, the inclusion or exclusion of the negative amounts in accounts 1640014 and 1650037 does not change the amounts or character of the prepaid pension and OPEB cash assets that should be included in rate base when all related non-cash accounts are considered.

Q. CAN YOU EXPLAIN THE PURPOSE OF THE NON-CASH ASC 715 ACCRUAL ADJUSTMENT BALANCE SHEET ACCOUNTS, INCLUDING THE NEGATIVE AMOUNTS IN ACCOUNTS 1650014 AND 1650037?

A. Yes. The prepaid assets related to pension and OPEB are recorded on the Company's books under FASB ASC 715, Compensation - Retirement Benefits. The Company has recorded the cash prepaid pension balance in Account 1650010 and cash prepaid OPEB balance in Account 1650035 and included such balances in rate base. The balances in Account 1650010 and 1650035 reflect the Company's cumulative cash contributions in excess of cumulative pension and OPEB cost. There are also non-cash ASC 715 accrual adjustment balances recorded in Accounts 1290000, 1290001, 1290002, 1290003, 1650014, 1650037, 1823165, 1823166, 1900010, 1900011, 2190006, 2190007, 2283006, and 2283016 that result from the Non-Cash ASC 715 Reclass entries required by ASC 715 to separate the calculated prepayment into two separate components – the funded status and accumulated other comprehensive income (or a regulatory asset) for gains and losses that have not yet been recognized as components of net periodic benefit cost.

To recognize the funded positions, the Company records a series of balance sheet entries for the components of Kentucky Power Company's pension and OPEB plan prepayments. Specifically, for periods in which Kentucky Power Company's pension and OPEB plans are in an overfunded position, the Company records an asset balance to Account 129 for the overfunded amount, and for periods in which Kentucky Power Company's pension and OPEB plans are under-funded, the Company records a liability balance to Account 228.3 for the net under-funded amount.

The Company records, as a component of accumulated other comprehensive income, Account 219, the changes in the funded status that arise during the year that are not recognized as a component of net periodic benefit cost, with the tax effect recorded to Account 190, Accumulated deferred income taxes. A regulatory asset is recorded to Account 182.3 instead of accumulated other comprehensive income for qualifying benefit costs of regulated operations that are deferred for future recovery.

The total of the funded status recorded to Account 129 or 228.3, and the cumulative funded status adjustment recorded to Accounts 219 and Account 190, or Account 182.3 as applicable, will equal the corresponding pension and OPEB plan prepayments recorded to Account 165. In other words, these entries simply move amounts between various balance sheet accounts to facilitate financial reporting in accordance with ASC 715, but do not alter the original transactions of recording cash contributions to the pension and OPEB trust as a prepayment and recording expenses as the prepayment is used.

Q. WITNESS KOLLEN CRITICIZES THE COMPANY FOR IGNORING THE NEGATIVE AMOUNTS IN ACCOUNTS 1650014 AND 1650037 FOR RATE BASE PURPOSES. DOES MR. KOLLEN IGNORE THE OTHER NON-CASH BALANCE SHEET ACCOUNTS IN HIS TESTIMONY RELATED TO PENSIONS AND OPEB?

A. Yes. The Company's response to AG/KIUC 2-17, which is attached to the testimony of AG/KIUC Witness Kollen as Exhibit __ (LK-9), provided the complete list of Non-Cash ASC 715 Reclass accrual adjustment accounts including Accounts 1650014 and 1650037 as well as Accounts 1290000, 1290001, 1290002, 1290003, 1823165, 1823166, 1900010, 1900011 2190006, 2190007, 2283006, and 2283016 that are excluded from rate base and have no effect on ratemaking because they zero out thus leaving, for ratemaking, the proper amount of prepayment financed by the Company.

Q. WOULD IT BE APPROPRIATE TO INCLUDE THE NEGATIVE AMOUNTS IN ACCOUNTS 1650014 AND 1650037 IN RATE BASE WITHOUT INCLUDING THE OTHER NON-CASH ASC 715 RECLASS BALANCE SHEET ACCOUNTS?

A. No, it would be very inappropriate to include only part of the Non-Cash ASC 715 Reclass pension and OPEB balance sheet accounts in rate base as suggested by AG/KIUC Witness Kollen. As previously discussed, this would be an erroneous departure from the basic accrual accounting concept of balanced journal entries and would be improper ratemaking by ignoring an asset financed by the Company.

Q. WOULD THE RESULT CHANGE IF ALL OF THE NON-CASH ASC 715 RECLASS BALANCE SHEET ACCOUNTS WERE INCLUDED IN RATE BASE VERSUS EXCLUDING ALL OF THESE ACCOUNTS AS THE COMPANY HAS DONE?

A. No, the impact on rate base would be exactly the same as that recommended by the Company in this proceeding. Below are the Kentucky Power Company balances at March 31, 2020 associated with the pension and OPEB prepayments:

Kentucky Power Company
Pension and OPEB Balances as of March 31, 2020

Line No.	Account	Description	Pension	OPEB	Subtotal Tie Out
1	1650010/ 1650035	Prepayment - Contributions	$44,879,334	$20,174,958	A
2	1650014/ 1650037	ASC 715 Prepayment Reclass	(44,879,334)	(20,174,958)	B
3	1290000/ 1290001/ 1290002/ 1290003	ASC 715 Trust Funded Positions (Assets)	-	23,899,853	B
4	2283016/ 2283006	ASC 715 Trust Funded Position (Liabilities)	(1,409,642)	-	B
5	1823165/ 1823166	ASC 715 - Regulatory Asset	45,132,948	(1,602,940)	B
6	1900010/ 1900011	ASC 715 - ADFIT Asset	242,766	(445,610)	B
7	2190006/ 2190007	ASC – 715 Other Comprehensive Income	913,262	(1,676,344)	B
8		Total ASC 715 Entries	-	-	= ∑ B's
9		Total Prepayment Contributions	44,879,334	20,174,958	= A
10		Total	$ 44,879,334	$ 20,174,958	= A + ∑B's

As can be seen above, the Non-Cash ASC 715 Reclass entries zero out (Line 8) leaving the cash prepayment that is the Company's cumulative contributions in excess of cumulative pension and OPEB cost (Line 9). For ratemaking, the Company has traditionally excluded the Non-Cash ASC 715 Reclass accounting entries because it is simply geography on the balance sheet for financial reporting purposes. However, another option would be to include all the Non-Cash ASC 715 Reclass accounting entries along with the cash prepayment (sum of Lines 8 and 9, as shown in Line 10). Either way, the end result is the Company's request in this case, which reflects the cash prepayments in rate base.

Q. DO YOU HAVE ANY COMMENTS REGARDING MR. KOLLEN'S STATEMENT THAT "THE COMPANY'S ACCOUNTING REFLECTED IN THESE FOUR ACCOUNTS [1650010, 1650035, 1650014, AND 1650037] IS NOT REQUIRED, DEFINED, OR DESCRIBED BY GAAP OR THE FERC USOA?"

A. Yes. Contrary to AG/KIUC Witness Kollen's claim, prepaid pension and OPEB assets exist under GAAP. Consistent with GAAP, a prepaid pension asset and a prepaid OPEB asset exist when contributions to the related trust fund exceeds the amount of cost that is recorded. Pension and OPEB cost required to be recorded under GAAP is net of the earned return on plan-related investments.

It is important to note that under Statement of Financial Accounting Standards ("SFAS") 87, *Employers' Accounting for Pensions*, the GAAP accounting predecessor to SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* (now codified in ASC 715), the prepaid pension asset is explained as arising from an employer's cumulative cash contributions in excess of cumulative pension cost. Paragraph 35 of SFAS 87, as originally issued, states:

> A liability (unfunded accrued pension cost) is recognized if net periodic pension cost recognized pursuant to this Statement exceeds amounts the employer has contributed to the plan. An asset (prepaid pension cost) is recognized if net periodic pension cost is less than amounts the employer has contributed to the plan.

Q. DO CURRENT ACCOUNTING STANDARDS STILL USE THE ABOVE APPROACH FOR CALCULATING A PREPAID PENSION ASSET?

A. Yes, the prepayment continues to represent the difference between cash contributions to the plan trust fund and the actuarially determined cost recorded on the books. Kentucky Power Company implemented SFAS 158 (now codified in ASC 715), which results in accounting entries (Non-Cash ASC 715 Reclass) to separate the calculated prepayment into two separate components – Kentucky Power Company's funded position (either an asset or liability) and accumulated other comprehensive income or a regulatory asset balance for the timing difference between the amount recorded as expense and the amount recovered from customers over time. The Non-Cash ASC 715 Reclass entry moves amounts between various balance sheet accounts for financial reporting purposes, but doesn't change the character of the original transaction of making a cash contribution to the pension trust and recording pension expense. In the end, a prepayment remains that is separated into two components on the balance sheet – funded position and accumulated other comprehensive income or regulatory asset.

If Kentucky Power Company's contributions to the pension and OPEB trust funds are equal to the GAAP-determined plan cost, there would be no related prepaid asset or liability and the Company would recover this pension and OPEB cost from customers. If Kentucky Power Company's contributions to the pension and OPEB plan trust funds are less than the GAAP-determined plan cost, the Company would have a liability. For periods in which Kentucky Power Company makes contributions above the GAAP-determined cost, the Company has a prepaid asset that, as described above, is a cash asset that has been financed by the Company.

Q. DOES MR. KOLLEN IMPLY THAT THE COMPANY IS NOT COMPLYING WITH GAAP AND ASC 715 IN REGARDS TO ACCOUNTING FOR PREPAID PENSION AND OPEB ASSETS?

A. It is not entirely clear, but it is baseless if that is his assertion. Two different external auditors have issued opinions since ASC 715 was implemented and both auditors have issued “unqualified” or clean opinions regarding the Company’s financial statements and disclosures, including the accounting for Kentucky Power Company’s pension and OPEB plans.

Q. IS WITNESS KOLLEN’S CLAIM THAT “AEP HAS DEFINED THESE ACCOUNTS…TO ASSIST THE OPERATING COMPANIES IN THEIR ATTEMPTS TO INCREASE RATE BASE BY INCLUDING ONLY THE POSITIVE AMOUNTS IN ACCOUNTS 1650010 AND 1650035 IN RATE BASE” ACCURATE?

A. No, this accusation is baseless and incorrect. As stated earlier, the ASC 715 balance sheet accounts are part of reclass entries for financial reporting purposes and zero out, leaving the true cash financed asset. As supported by my direct testimony, the amounts recorded in accounts 1650010 and 1650035 are composed of Kentucky Power’s cumulative cash contributions in excess of cumulative pension and OPEB cost and the Non-Cash ASC 715 Reclass amounts are irrelevant for ratemaking purposes.

Further, the “return on” component of Kentucky Power’s base revenue requirement has historically been computed based on capitalization, which inherently reflects amounts financed by the Company (such as prepaid pension and OPEB amounts) and excludes non-cash transactions. Company Witness Vaughan’s rebuttal testimony supports the Company’s continued use of capitalization to compute the “return on” component of the revenue requirement, as proposed in the Company’s Application. Kentucky Power Company’s consistent approach discredits Mr. Kollen’s claim.

AG/KIUC Witness Kollen is the only witness in this proceeding proposing that Kentucky Power transition to use of rate base to compute the "return on" component of the revenue requirement.

Q. DOES WITNESS KOLLEN ACKNOWLEDGE THAT THE COMMISSION HAS PREVIOUSLY APPROVED A PREPAID PENSION ASSET IN RATE BASE FOR THE COMPANY AND/OR THAT THE PREPAID PENSION ASSET BENEFITS KENTUCKY POWER CUSTOMERS THROUGH REDUCED COST OF SERVICE?

A. No. Mr. Kollen fails to acknowledge that the prepaid pension asset was included in total rate base authorized Case No. 2017-00179, the Company's last base case proceeding. Further, he does not acknowledge that the prepayment benefits customers by reducing pension cost included in the Company's cost of service, as supported by Exhibit HMW-R3.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED A PREPAID OPEB ASSET IN RATE BASE?

A. No. This current proceeding reflects the Company's initial request to include prepaid OPEB asset in rate base. The prepaid OPEB asset was established on the Company's books in March of 2014; however, was inadvertently omitted from rate base presented in the Company's base case filings in Case No. 2014-00396 (historical test year ended September 30, 2014) and Case No. 2017-00179 (historical test year ended February 28, 2017). The prepaid OPEB asset has benefitted customers since its establishment in 2014 by reducing pension cost included in the Company's cost of service to a negative amount, as supported by Exhibit HMW-R3.

Q. DOES WITNESS KOLLEN ACKNOWLEDGE THAT THE PREPAID OPEB ASSET BENEFITS KENTUCKY POWER CUSTOMERS THROUGH REDUCED COST OF SERVICE?

A. No, Mr. Kollen is proposing to remove the prepaid OPEB asset from rate base without making a corresponding adjustment to remove the related benefit of reduced OPEB cost from the cost of service.

Q. DOES YOUR SILENCE ON A PARTICULAR COMMENT OR ASSERTION IN WITNESS KOLLEN'S TESTIMONY REGARDING PENSION AND OPEB ASSETS MEAN THAT YOU AGREE WITH SUCH COMMENT OR ASSERTION?

A. Absolutely not. I limited my rebuttal to the most significant issues on this subject raised in his testimony.

Q. WHY IS IT APPROPRIATE THAT THE COMPANY BE ALLOWED TO INCLUDE ITS PREPAID PENSION AND OPEB ASSETS IN RATE BASE?

A. Kentucky Power Company has prepaid allowable pension and OPEB expenses and the inclusion of the prepayments in rate base is consistent with well-accepted ratemaking principles and Commission precedents and is necessary both to compensate the Company for use of the investor funds it has advanced and to avoid a disincentive to the Company for making similar prudent advances in the future on behalf of its employees. Such treatment is particularly warranted where, as here, the prepayments lowered both the current and future cost of providing service and thus benefited customers and the Company's ongoing ability to provide reliable service along with providing assurance to the Company's employees that there will be funds to pay their retirement benefits.

Q. IS AN ADJUSTMENT TO THE COST OF SERVICE WARRANTED IF THE COMMISSION ADOPTS AG/KIUC WITNESS KOLLEN'S RECOMMENDATIONS TO COMPUTE THE "RETURN ON" COMPONENT OF THE REVENUE REQUIREMENT USING RATE BASE AND REMOVE PREPAID PENSION AND OPEB ASSETS FROM RATE BASE?

A. Yes, because without these additional contributions, the Company's pension and OPEB expense would be higher. Thus, if the pension and OPEB prepayments are removed from rate base, the Company's cost of service for the test year ended March 31, 2020 should be increased in order to remove $3.7 million benefit (lower expense) resulting from these additional contributions, as supported by Exhibit HMW-R3.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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E-Signature Summary

Signer 1: Heather M. Whitney (HMW)
November 03, 2020 10:36:31 -8:00 [5D41CF5B6386] [167.239.221.84]
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E-Signature Notary: Sarah Smithhisler (SRS)
November 03, 2020 10:36:31 -8:00 [F11A75C32513] [167.239.221.81]
srsmithhisler@aep.com
I, Sarah Smithhisler, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Heather M. Whitney, being duly sworn, deposes and says she is the Director in Regulatory Accounting Services for American Electric Power Service Corporation that she has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of her information, knowledge and belief after reasonable inquiry.

Heather M. Whitney
Signed on 2020/11/03 10:36:31 -8:00

Heather M. Whitney

STATE OF OHIO)
) Case No. 2020-00174
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Heather M. Whitney this 3rd ____, of November 2020.

NOTARY PUBLIC
STATE OF OHIO
Sarah Smithhisler
Commission # 2019-RE-775042
Electronic Notary Public
State of Ohio
My Comm Exp. Apr 29, 2024
Notary Stamp 2020/11/03 11:36:31 PST F11A75C32513

S. Smithhisler
Signed on 2020/11/03 10:36:31 -8:00

Notary Public

Notary ID Number: 2019-RE-775042

Rebuttal Exhibit
CMG-7 is
being provided in a
separate file in Excel
format.

1 Accounting for Public Utilities § 4.04

Accounting for Public Utilities > II RATEMAKING CONCEPT > CHAPTER 4 Determination of Utility Rate Base

§ 4.04 Items Included in Rate Base

[1] Plant in Service

Plant in service is the most important component of a utility's rate base. This item commonly represents the substantial majority of the total rate base amount, after a deduction for related accumulated depreciation and amortization. The significance of plant in service is easily understood in light of the tremendous amount of capital invested in the construction of utility facilities. Major expenditures are required for land acquired for construction sites, construction material and supplies, operation of construction-related equipment, and construction-related labor activities. In addition, overhead allocations are required for those general expenses incurred which are, at least in part, due to utility construction (administrative payroll, engineering design, employee pension expense, sales tax, etc.). Furthermore, financing costs are generally capitalized as a component of plant cost during the construction period. In the case of electric power generation from nuclear fuels, the extensive costs of procurement, refinement, enrichment, and fabrication of the fuel are also capitalized as a separate component of the utility plant. Despite being the largest component of the rate base, utility plant is generally one of the less controversial areas in a rate proceeding. However, the prudency of expenditures or the usefulness of plant if large amounts of excess capacity exist is sometimes challenged. The amount expended during construction also may be challenged.

[2] Acquisition Adjustments

The general rule related to the acquisition of utility plant previously used in the utility function is that the rate base component for the plant includes only the original cost, net of accumulated depreciation, of the property to the first owner devoting the property to public service. Therefore, if a utility acquires major fixed assets (i.e., an operating unit or system) from another utility by purchase, merger, consolidation, liquidation, or otherwise at a price in excess of the seller's original cost (net of accumulated depreciation), the addition to the acquiring utility's rate base reflecting the acquired assets may be limited to the undepreciated original purchase price. If an amount paid for utility plant exceeds its original cost depreciated, and that amount is recoverable through future rates, the fair value of the plant has been increased and an acquisition adjustment should be recorded as a component of utility plant. With a business combination, if the excess payment is not included in future rates, that amount typically represents goodwill or an intangible asset rather than a plant acquisition adjustment.

The FERC's accounting policy staff issued related guidance in July 2003, which states that "amounts so allocated to utility plant in excess of depreciated original cost at the date of acquisition should be an acquisition adjustment in Account 114 (Electric/Gas Plant Acquisition Adjustments) and the excess of the cost of the acquired company over the sum of the amounts assigned to all identifiable assets acquired and liabilities assumed should be recorded as goodwill in Account 186, "Miscellaneous Deferred Debits." In such situations the acquisition adjustment would be amortized to the income statement consistent with the recovery through rates and the goodwill would not be amortized." See *Chapter 11* for a detailed discussion of the Uniform Systems of Accounts.

The necessity of this separate accounting treatment is largely a consequence of certain abuses in the utility industry during the acquisition and merger period of the 1920s and 1930s. (See *Chapter 2* for a detailed discussion.) Through the process of acquiring utility assets or entire utility companies at prices in excess of depreciated cost, purchasing utilities were able to write up their basis in plant assets. If these purchase prices were in excess of the "value" of the property, the utility was able to inflate its rate base artificially. This situation often occurred if the purchase was from an affiliated company under the ownership of a common utility holding company. By effectively trading properties, commonly owned utilities were able to inflate their rate bases through transactions that lacked any economic substance.

The outgrowth of this situation was a general consensus among regulators that utility customers should not pay on an amount in excess of the cost when property was originally devoted to public service, since any excess represented only a change in ownership without any increase in the service function to utility ratepayers. By accounting for acquisition adjustments separately from plant in service, these excess costs could be better controlled by regulatory authorities as to their ultimate disposition.

Two basic questions surround the ratemaking treatment referred to above of the various amounts included in the acquisition adjustments account:

(1) should any of the amounts be accorded rate base treatment; and

(2) should the amortization of any of these balances be considered in cost of service?

Rate base and cost of service treatment are often inconsistent when commissions deal with the acquisition adjustments issue.

Rate base treatment and/or cost of service treatment has been allowed by various regulatory commissions under a variety of circumstances. The reasons most commonly cited for allowing rate base and/or cost of service treatment of acquisition adjustments are as follows:

(1) when acquisitions represent an essential or desirable part of an integration of facilities program devoted to serving the public better;

(2) when acquisitions are clearly in the public interest, because operating efficiencies offset the excess price over net original cost; and

(3) when acquisitions are determined to involve arm's-length bargaining.

A substantial number of cases exist where rate base and/or cost of service treatment has been allowed as a result of satisfying one or more of the criteria listed above. For example,[4] in 2010, the Colorado Public Utility Commission allowed both rate base and cost of service treatment for the acquisition adjustments related to Public Service Company of Colorado's (PSCo's) purchase of certain Calpine generating facilities where the acquisitions were deemed to be the least cost option for satisfying PSCo's resource needs.

In the 1955 case of *Arlington County v. Virginia Electric Power Co.,*[5] the Virginia Supreme Court of Appeals ruled that the Virginia State Corporation Commission had properly allowed both rate base and cost of service treatment for an amount paid at arm's-length bargaining in excess of original cost when first devoted to public use. When the Louisiana Public Service Commission allowed Louisiana Power and Light Company rate base and cost of service treatment for certain acquisition adjustments, the Louisiana Commission relied upon several of the criteria previously discussed. To quote from the Louisiana Commission's 1946 decision:

> "The owners of a public utility are entitled to earn and receive a fair rate of return upon the money prudently invested in property used and useful in rendering public service. Money is prudently invested, even though it is in excess of the original cost of the property purchased, if the excess of purchase price over original cost was paid as the result of arm's-length bargaining between nonassociated buyer and seller, if the excess was necessary for the integration of the property into a larger and more efficient system, and if the purchase necessitating the excess did or reasonably should have resulted in public benefit by improvement of service to customers or in lowered rates or both better service and lowered rates. This integration cost or excess of purchase price over original cost termed in prescribed system of accounts as 'Utility Plant Acquisition Adjustments' should remain a part of the prudent investment during the life of the physical property to which it was applied, and its extinguishment from the investment when and if required by the Commission, should be accomplished by amortization through annual charges to

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[4] Reserved.

[5] *196 Va 1102 (Va 1955)*.

Operating Revenue Deductions during the life of the property remaining after the date of the purchase which created the excess."[6]

Although the FERC generally excludes acquisition adjustments from rate base treatment, it will permit the inclusion of these balances in the rate base for allocation purposes only (that is, allocating utility assets between jurisdictional and nonjurisdictional rate base) if the related state regulatory commission allows rate base treatment of the adjustments.

The FERC reiterated its position in excluding acquisition adjustments from rate base treatment in an order dated June 25, 1998.[7] In this case, Duke Energy requested rate base treatment of the acquisition adjustments resulting from its purchase of two California "reliability must-run" (RMR) generating facilities from Pacific Gas & Electric Company. The FERC summarily denied recovery of the acquisition adjustments indicating that the traditional criteria for recovery of acquisition adjustments do not apply in today's competitive energy marketplace. The FERC further indicated that Duke Energy's intent in purchasing the RMR generating facilities was to sell power in a competitive power market and, accordingly, Duke will have the opportunity to recover the acquisition adjustments through market-based rates when the facilities are not operating in a must-run status.

In another case, the FERC allowed an acquisition adjustment to be included in the distribution rate it allowed one utility to charge another when it found that there were material benefits to ratepayers. In this case, the acquisition adjustment was part of the cost of the Long Island Power Authority's (Authority) acquisition of the Long Island Lighting Company (LILCO). The Authority is a municipal subdivision of New York State that was created to acquire LILCO's securities and assets. The utility acquiring the power and challenging the inclusion of the adjustment acquisition in the distribution rate was Suffolk County Electrical Agency, a municipal power agency. The need for an adjustment was created because the Authority acquired nonproductive assets from LILCO, particularly the never-opened and very expensive Shoreham nuclear power plant. The FERC held that the acquisition adjustment was properly allocable to the Authority's distribution rate because almost the entire benefit of the Authority's acquisition of LILCO flowed to Long Island's retail customers and was related to the lower cost of financing for plant assets and debt.[8]

As a general rule, when acquisition adjustments are allowed in the rate base, amortization to cost of service is also allowed, and, if a return is not allowed, amortization is required below-the-line. Some regulatory commissions, however, have allowed inconsistent treatment principally as a means of sharing the costs associated with acquisition adjustments between investors and ratepayers. For example, the North Carolina Utilities Commission allowed Duke Power Company to amortize certain acquisition adjustment balances to cost of service but disallowed rate base treatment.[9]

On occasion, a utility may purchase used plant at a price lower than the net book value in the hands of the selling utility, thus creating a negative acquisition adjustment. These transactions are generally accounted for by a debit to plant in service for the net original cost with a credit to the acquisition adjustment account for the deficiency. In these cases, a similar question arises regarding the handling of the credit acquisition adjustments for ratemaking purposes. The regulatory commissions and courts have varied in their opinions as to the appropriate treatment of these balances and have not necessarily followed the same reasoning as followed regarding ratemaking treatment for debit adjustments. In general, credit balances are used to reduce the rate base and are also amortized above-the-line (as a reduction of operating expenses) with what appears to be greater frequency than corresponding treatment for debit adjustments. However, the FERC currently treats a negative acquisition adjustment as a credit to accumulated depreciation. Consistent reasoning regarding the treatment of debit and credit adjustments, however, does exist and is exemplified in a 1973 order of the Vermont Public Service Board in a rate proceeding involving Vermont Gas Systems, Incorporated:

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[6] *Re* Louisiana Power and Light, 65 PUR (NS) 23 (La 1946).

[7] Dkt ER-98-2668-000.

[8] [102 FERC ¶ 63,037 (March 12, 2003)](#).

[9] *Re* Duke Power Co, 26 PUR4th 241 (NC 1978).

" 'Original cost' relates to the cost incurred by the utility purchasing the facility, not the original cost of a prior owner. Assuming prudent investment, the stockholders should be allowed to earn a return on their actual 'out-of-pocket' investment; the fact that the marketplace may place a higher *or lower* valuation on the property does not affect the amount of the actual price paid by petitioner."[10] (Emphasis added.)

The basis for disallowing rate base treatment of acquisition adjustments is the assumption that the rate base should include only the net original cost to the utility first devoting the property to public use. In GAAP based financial statements the excess of fair value of acquired net assets over cost should be accounted for in accordance with ASC 805-30-10 and 11.

In cases where used property is purchased from nonutility sellers, there generally is no acquisition adjustment, since the property has not previously been utilized in providing utility services. In these cases, net original cost is the purchase price paid by the acquiring utility. However, we are aware of recent transactions in which the FERC staff required a purchaser to record the amount paid over net original cost as a plant acquisition adjustment. A question that has occasionally been raised concerns the purchase of used property from another utility (rate regulated enterprise) not involved in the same utility operation and therefore subject to a different scheme of regulation. While this issue has not been raised often, it appears that in most cases the general rule is interpreted broadly to encompass the first regulated enterprise of any type devoting plant to public service. A court case related to this matter involved the purchase of electric transmission lines by Montana Power Company from Chicago, Milwaukee, St. Paul & Pacific Railroad. In this 1979 case, the U.S. Court of Appeals ruled that the property had previously been devoted to public use by a regulated enterprise and that only the original cost to the original user should therefore be allowed in rate base.[11]

[3] Accumulated Depreciation and Amortization

Recovery of the dollars invested in plant in service is permitted over the plant's estimated useful life by a systematic depreciation charge to cost of service, normally on a straight-line basis with an equal portion of the original cost investment (net of estimated salvage less removal costs) recovered in each period over the estimated service life of the related fixed assets. The subject of utility depreciation accounting is examined in detail in *Chapter 6*.

Deduction of the reserves accumulated for annual depreciation and amortization charges from a utility's rate base is an accepted principle of rate base development, with the reserve balances generally calculated on the same basis as that used for determining rate base plant in service (13-month average, year-end, etc.). Theoretically, the accumulated reserves have already been collected from utility customers through the cost of service treatment for depreciation and the resulting revenue requirements generated. Deducting accumulated reserves from the rate base prohibits the utility from earning a further return on costs that have been recovered and also avoids the confusion of attempting to equate net plant in service (unamortized cost investment) with any measure of current "value" of the property. It does not matter if net plant in service is not an accurate measure of the property's current value (and it most likely is not). Accumulated depreciation in investment cost jurisdictions is not designed to force net plant to equal current value but instead is simply used to reduce the rate base for that portion of plant investment and net salvage already recouped through rates.

For regulatory jurisdictions following the fair value approach to rate base development, determination of the appropriate accumulated depreciation balance is the subject of considerable controversy, with the specific techniques employed varying widely among the different regulatory commissions. With this approach, accumulated depreciation is more closely associated with an attempt to measure the "current value" of utility plant, with a corresponding recognition of the value that has been "used" since the plant was placed in service. Examples of the methods employed for determining depreciation reserves under the fair value concept include:

(1) determining the fair value of gross plant and then attempting to calculate the necessary depreciation reserve to reflect the cumulative loss in value in current dollars; and

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[10] *Re* Vermont Gas Sys, 100 PUR3d 209 (Vt 1973).

[11] *Montana Power Co v Federal Energy Regulatory Commn, 31 PUR4th 191 (9th Cir 1979)*.

(2) determining the fair value of gross plant and then calculating the related depreciation reserve by multiplying gross plant by the same percentage as the ratio of original cost accumulated depreciation to gross original cost plant.

Concepts for estimating fair value depreciation are discussed in more detail in *Chapter 6*.

Sometimes, depreciation reserves are determined to be either too small or too large, usually as a result of either the experience being different than what was expected or the modification of future expectations. In those cases where the reserves are found to be too small, the reserve difference is commonly the result of two possible factors. Earlier estimates of service lives may have been too long as a result of changing circumstances, such as current technological advances and/or changes in regulatory operating requirements, or increases in the current estimates of removal costs when the associated plant will be retired.

The ratemaking treatment of reserve differences varies from one regulatory commission to another, especially in cases where the differences are significant. Usually, the difference is recovered or credited through the use of “remaining life” depreciation rates, in which the total unrecovered investment and net salvage is depreciated over its estimated remaining life. Occasionally, for regulatory purposes, accumulated depreciation is adjusted upward to eliminate the deficiency, and the rate base is reduced for the entire accumulated reserve. When the accumulated reserve is adjusted, the debit side of the adjustment is either amortized to cost of service or eliminated against retained earnings. Amortization to cost of service is generally allowed where the utility can demonstrate that it was not negligent in failing to adjust depreciation rates at an earlier time, since the circumstances leading to the deficiency were largely unforeseen. In rare cases, commissions have not required rate base reduction for differences and still allowed amortization of the debit adjustment to cost of service. For instance, the New York Public Service Commission allowed such treatment to the Iroquois Gas Corporation in 1970 where it was determined that factors unforeseen to the utility resulted in shorter lives and sharp increases in negative salvage and that the utility would be unduly penalized “for encountering the vicissitudes of conducting a business enterprise.”[12]

In those situations where the reserve is determined to be too high, the reserve difference usually results from an upward adjustment in current estimated service lives beyond the estimates previously utilized. Regulatory treatment of these reserve differences also vary among regulatory jurisdictions. Most commonly, the entire reserve is deducted from the rate base under the premise that any downward adjustment to the reserve will result in ratepayers paying again in the future for depreciation already recouped through previous cost of service deductions. Thus, adjustment of the reserve excess is generally prospective through revised future depreciation provisions with no penalty imposed for the excess past charges.

[4] Construction Work in Progress (CWIP)

Historically, CWIP was not included in the rate base under the theory that rate base treatment violates two interrelated principles of utility ratemaking—only property that is used and useful should earn a rate of return, and interperiod equity requires an allocation of costs (and the rates they generate) to those specific periods when the costs actually provide service to ratepayers. In other words, present customers should be required to pay only for construction costs directly incurred in providing their specific service.

When utilities are not allowed to earn a return to cover their construction financing costs during the construction period, they are allowed to capitalize the financing costs for future recovery through an allowance for funds used during construction (AFUDC). This capitalized cost, which is added to the basis of utility plant under construction, will ultimately be included in the rate base as a component of plant in service, thereby earning a return and being recovered through depreciation allowances. Although the actual mechanics of computing AFUDC may be challenged, there is little debate over the propriety of including AFUDC as a component of construction costs along with materials, labor, overhead, and the like. The actual mechanics of computing AFUDC are discussed in greater detail in *§ 4.04[5][b]*, below.

While rate base treatment of CWIP has historically been denied, inclusion in the rate base is often allowed where a significant amount of plant will be in service in the immediately foreseeable future, even in those cases

[12] *Re* Iroquois Gas Corp, 85 PUR3d 359 (NY 1970).

where a future test period is not employed. This is especially true if the plant is actually in service after the test period but before the rate order, or if the plant is anticipated to be in service in the near future and is expected to affect operations significantly. Often the inclusion of the post-test period CWIP in the rate base necessitates other rate case adjustments to reflect properly anticipated operating changes resulting from this new plant addition. Some of these operating changes that may require other rate case adjustments include the retirement of other utility plant, lower cost of service due to greater operating efficiency of new plant, changes in fuel cost mixtures, and changes in depreciation expense (usually higher due to new plant being costed at more current dollars). In addition to the above circumstances, commissions often allow CWIP in the rate base where the plant additions possess one or more of the following characteristics:

(1) Additions are basically minor replacements and therefore are neither revenue-producing nor expense-reducing assets.

(2) Additions do not affect the overall level of operations.

(3) Additions are specifically being made to improve the environment or improve the quality of utility service.

Further, a tendency developed in the late 1970s, primarily in the electric industry, to include portions of CWIP as a rate base component and to discontinue the capitalization of AFUDC. This trend largely resulted from conditions then faced by a substantial portion of this industry. Very long-term construction projects with high financing costs resulted in amounts of capitalized AFUDC that produced disproportionate contributions to reported net income. In some cases, AFUDC earnings actually exceeded reported net income. This AFUDC income did not supply cash funds for the payment of interest costs and dividends; therefore, utilities with extensive construction programs often found themselves in an extremely tight cash flow situation. This in turn led investors to discount AFUDC earnings, which in turn resulted in relatively higher costs associated with future financings—a product of the perceived higher risk. Recognition by some commissions of the second-class status being assigned to AFUDC earnings is exemplified in this quotation from the New Jersey Board of Public Utilities:

> “The investment community is no longer enamoured with AFUDC earnings. They have been discounted. Investors look to the quality of earnings in real dollars and see through more nonconservative accounting principles. Replacing AFUDC earnings with real earnings is the most significant step this Board can take to increase investor confidence in this utility so that debt and equity can be sold at reasonable levels.”[13]

When consideration is given to the time value of money (with all other matters held constant), either the inclusion of CWIP in the rate base or the accrual of AFUDC results in the same overall charges to ratepayers. Because of the lower capitalized costs, the inclusion of CWIP in the rate base actually reduces the total cost to the utility and its customers over the life of the plant. In addition, increased cash flows associated with CWIP in the rate base avoids a certain amount of outside financing, which is advantageous whenever incremental borrowing costs exceed embedded costs. Further, the improved quality of actual cash earnings may allow required financings at relatively lower costs. Because of these factors, many now believe that ratepayers are better off financing construction costs currently (with the resulting increased service rates) rather than paying for even higher financing costs over the service lives of the assets.

In addition, many advocates of CWIP in the rate base are challenging the validity of the used and useful and interperiod equity arguments. They contend that the used and useful concept fails to address the realities of the economic environment in which utilities presently operate, because funds invested in CWIP represent an investment necessary to provide continuing service and CWIP is therefore currently used and useful. They believe that CWIP investment is no different from material and supplies, prepayments, and PHFU, all of which are allowed in the rate base by the majority of the regulatory commissions. As for the interperiod equity argument, CWIP advocates believe that the economic environment in which utilities operate negates the protective intent of a principle developed in an entirely different technological and economic era. In other words, the premise that present customers should pay only for costs incurred in providing their direct service while recognition of costs benefiting future customers should be deferred is no longer viable in the case of modern utility operations.

[13] *Re* Public Serv Elec and Gas, Docket No 744-335 (NJ 1975).

This change in economic conditions from the time when the "used and useful" and AFUDC concepts were first adopted is highlighted by a brief review of the economic developments of the electric industry. During its development stage, the industry was building new plants and facilities to provide the convenience of electricity to a larger proportion of the U.S. population. In its adolescent years, the electric industry continued to build additional capacity to provide energy for industrial development.

In the early 1950s, the electric industry reached maturity. That is, low-cost electric energy generally was available to the entire population of the United States. For the next 15 to 20 years, the industry continued to build largely to meet the increasing demands of current customers and the increasing size of the U.S. population.

Throughout this period of development, the industry was able to construct new facilities that had a lower cost per kilowatt than the facilities then in service. This was largely a consequence of economies of scale, few environmental restrictions, and relatively low capital costs. These conditions provided regulators with a basis for deferring the financing costs of new construction for ratemaking purposes through the AFUDC mechanism. They recognized that the power generated and delivered through these new facilities would be cheaper than power generated by existing plants upon which current customer rates were based. Therefore, to balance the interest of present customers with those of future customers, a case could be made for deferring the financing costs of new construction. Even though the deferral of financing costs was contrary to generally accepted accounting doctrine for industry in general at the time, the accounting profession accepted this treatment for the utility industry, since such deferral accounting was the basis for establishing rates and a matching of revenues and expenses would be achieved. The investment community accepted the deferral treatment, because the electric industry was healthy. That is, more efficient plants were being built, construction periods were relatively short, and the industry had sufficient cash flow to meet its capital cost requirements until the new plants went into service.

The electric industry has experienced significant changes in economic conditions affecting the costs of delivering energy. While the costs of new facilities were historically less per kilowatt than existing facilities on routine basis, the current economic trend is not as clear. In certain situations, the cost of new facilities may exceed the costs of existing facilities due to the impact of new environmental requirements, the cumulative impact of inflation, or other reasons. In other situations, new facilities may result in a lower cost than existing facilities due to benefits associated with enhanced efficiency or utilization of a lower cost fuel source or renewable technologies.

As a result of these changed conditions, today's customers are using the economic value of facilities that will cost a great deal more to replace per unit of capacity.

The decision by some regulators to allow CWIP in rate base, in whole or in part, is thus based on a broader understanding of the "used and useful" concept and on a recognition that different conditions exist today than when the "used and useful" position was employed by regulators to balance the interests of current and future ratepayers.

A quotation from the Florida Public Service Commission is a good example of the philosophy adopted by some regulatory bodies currently allowing CWIP in rate base:

> "The electric utilities in this state are currently undertaking massive construction programs. Included in these programs are additional nuclear generating facilities, which require construction lead times in the area of ten years. It is common knowledge that one electric utility in the state has had to delay the completion of a large nuclear facility due to cash-flow problems. This type of delay is very costly due to the fact that substantial amounts of carrying costs (AFDC) are being added to the cost of the facility, even though physical construction has slowed to a minimal pace."

> "Faced with the problems of extremely long lead times in the construction of nuclear units, and the possibility that huge sums of money would be tied up in construction from which there would be no cash flow whatsoever, we are aware that many utilities are canceling plans for nuclear units. This is taking place irrespective of engineering economics, since the utilities are going to fossil units in an effort to obtain as much capacity for their dollars as possible. In such cases, it is obvious that the fuel cost savings associated with nuclear fuel will not be achieved."

"After considering these factors, as well as the fact that the inclusion of CWIP in rate base with a concurrent cessation of AFDC charges cannot produce a double return to the company, we conclude that the company's proposal should be accepted. An increase in the amount of internally generated funds will enable the company to reduce the amount of external financing that would otherwise be required, thereby alleviating to some extent the debt coverage problem that the utilities are currently encountering. We would also expect that the adoption of such regulatory philosophy would enable utilities to reconsider the feasibility of constructing additional nuclear generating facilities if the engineering economics should dictate such a decision. Therefore, in an effort to improve the quality of the earnings of the company, we are accepting its proposal to include an additional $200 million of CWIP, in the rate base, on which no AFDC will be capitalized in the future and find the same to be reasonable and proper, and in the public interest."[14]

Other commissions, while still adhering to the general policy of excluding CWIP from the rate base, have allowed rate base treatment for certain portions of CWIP as a means of aiding a particular utility's general cash flow situation or as a means of alleviating cash flow problems associated with a particular construction project. An example of this philosophy toward CWIP in the rate base is the present FERC policy for the electric industry. The FERC currently follows Order No. 474-B, which permits electric utilities generally to include up to 50 percent of their FERC jurisdictional CWIP in rate base. Order No. 474-B also allows rate base treatment of CWIP related to the construction of pollution control facilities or the conversion of existing plants to conserve oil and natural gas, without reference to the 50-percent limitation. (Rate base treatment here is justified as being consistent with national goals.)

The inclusion of CWIP in the rate base requires the discontinuance of AFUDC capitalization at the appropriate time in order to avoid a double return on plant investment. Once CWIP is in the rate base and actually earning a return designed to cover construction-related financing costs, to continue AFUDC capitalization (which would later earn a return and be depreciated to cost of service) results in consumers paying twice for the same capital costs. The various commissions allowing CWIP in the rate base have generally developed accounting procedures designed to cut off AFUDC at the appropriate time (when rates based on including CWIP in the rate base become effective), thereby avoiding a double return problem.

On the other hand, some commissions have effectively allowed a partial return on CWIP investment through a procedure whereby CWIP is allowed in the rate base, while the capitalization of AFUDC continues with the AFUDC earnings included above-the-line in operating income. To the extent that the overall allowed return exceeds the AFUDC capitalization rate, the utility is currently earning a return on a portion of its construction investment.

In May 1983, the FERC issued Order No. 298.[15] This order provided for CWIP rate base treatment of pollution control and fuel conversion facilities and also allowed inclusion in rate base for not more than 50 percent of all remaining CWIP applicable to the wholesale rate base. Order No. 298 limited the effect of the rate increase associated with CWIP in rate base to no more than 6 percent in the first year and an additional 6 percent in the second year. A utility filing for CWIP in rate base was required to show that wholesale customers would not be charged for both capitalized AFUDC and a return on CWIP in rate base. If CWIP fell below the amount included in rate base, a utility was required to record negative AFUDC. Subsequently, the Commission also issued Order No. 298A[16] that includes a provision to permit wholesale customers to escape rates associated with CWIP in rate base if they prove that they bear no responsibility for the decision to build a new plant and will, in fact, not purchase full or partial requirements which involve the plant.

In September 1985, the Court of Appeals for the District of Columbia Circuit remanded these orders to the Commission for reconsideration.[17] The court found that the Commission's consideration of the potential "price squeeze" and "double whammy" effects of the rule was inconsistent and inadequate.

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[14] *Re Florida Power and Light, 9 PUR4th 156 (Fla 1975)*.

[15] Dkt No RM81-38 (May 16, 1983), effective July 1, 1983.

[16] Dkt Nos RM81-38-001 and RM83-38-012 (Oct 4, 1983).

[17] *Mid-Tex Elec Coop, Inc, et al v FERC, 773 F2d 327 (1985)*.

“Price squeeze” is alleged to occur when a utility’s rates for wholesale service are higher in relation to the costs of providing the wholesale service than are the utility’s rates for retail service in relation to the costs of providing retail service. This disparity of utility rules theoretically may result in an inability of the wholesale customer to compete with the utility for retail customers. Because retail rates are set by state commissions, price squeeze may be caused by the ratemaking policy differences between state commissions and the FERC.

“Double whammy” is alleged to arise when a wholesale customer is constructing its own generation facilities in order to supply itself with all or part of its future power requirements but, in the interim, must pay rates to the utility supplying its current needs that are based on certain CWIP in rate base.

In February 1986, the FERC issued Order No. 448,[18] which sets forth interim regulations reinstating its previous policy with certain modifications concerning the inclusion of CWIP in rate base.

In June 1987, the FERC issued a final rule regarding the inclusion of CWIP in rate base.[19] Order No. 474 addresses the concerns raised by the U.S. Appeals Court about possible anticompetitive implications. The provisions of this rule are substantially different from those presented in Order No. 298, but are similar to those put into effect on an interim basis in Order No. 448, with certain modifications intended to more thoroughly address the U.S. Appeals Court decision.

In October 1989, the FERC issued a modified CWIP order[20] in response to the U.S. Circuit Court of Appeals for the District of Columbia ruling that vacated part of the FERC’s Order No. 474.

In April 1990, the FERC issued Opinion No. 284-A in which it clarified certain price squeeze policies adopted in Opinion No. 284.

The trend toward increased rate base treatment of CWIP was influenced by the high cost of new plant investment, which produced more conditions in which rates had to be increased dramatically (rate shock) at the time that the plants went into service. It is hoped that acknowledgment of these conditions will continue to foster gradual recognition of construction financing costs during the construction period of the facility, as opposed to deferral of all costs to the future.

A step in this direction is the allowance of CWIP in rate base during the construction period of the plant and then, after the plant goes into service, capitalization of the return on the investment in plant for an arbitrary period of two to five years. This capitalization is limited to an amount equal to the AFUDC that would have been capitalized during the construction period. After the capitalization period (phase-in), the capitalized returns are recovered over the remaining life of the plant. An alternative to this approach is the application of “mirror-CWIP,” which allows certain CWIP in rate base and the continued capitalization of AFUDC with the associated income being deferred. Following construction of the plant, the AFUDC deferrals are amortized on an accelerated basis in order to lower the cost of service impact of the new plant.

By having increased rates (thereby sending early price signals to consumers) because of the inclusion of CWIP in rate base and by reversing that procedure in the early commercial life of the plant, a significant part of the peak in rates associated with new plants is smoothed out. This procedure was used a number of times in the 1980s and 1990s with respect to nuclear power plant construction and more recently with respect to certain significant new transmission line construction. In GAAP based financial statements “mirror-CWIP” should be accounted for in accordance with ASC 980-340-55-4 through 8.

[5] Allowance for Funds Used During Construction (AFUDC)

As discussed in the previous section, so long as CWIP is not included in the rate base, capitalization of the cost of funds during construction is proper. In January 1968, the FERC issued Accounting Release Number AR-5 (Revised). In AR-5, the FERC states that the proper period for capitalization of interest during construction begins with the date that construction costs are continuously incurred on a planned progressive basis. Capitalization of interest stops when the facilities have been tested and are placed in, or

[18] Dkt No RM86-6 (Feb 27, 1986).

[19] Order No 474, Dkt No RM86-6-000 (June 18, 1987).

[20] Order No. 474-B, Dkt No RM86-6, *modified by* Order No 626, Dkt No RM02-9-000.

are ready for, service. A company should cease the capitalization of interest for portions of construction projects completed and put into service although the entire project is not yet fully completed. The FERC further states that no interest should be accrued during a period of interrupted construction unless the company can justify the interruption as being reasonable under the circumstances.

The practice of capitalizing construction period carrying charges accomplishes a number of general objectives:

(1) The total costs of construction activities, including financing costs, are fully recognized.

(2) The utility operation is effectively shielded from costs associated with construction activities.

(3) The utility, by capitalizing the financing costs, is afforded an opportunity to recover the costs when the plant is placed in service.

Although the concept of AFUDC has long been recognized and followed in the utility industry, many aspects of AFUDC have been a source of vexation for both regulators and utilities. The controversy surrounding the computation of AFUDC and the proper treatment for ratemaking and financial reporting purposes has received considerable attention. This is especially true when conditions produce a surge in both financing costs and construction expenditures and the resulting increase in the amount of AFUDC, to a point where the effect of these non-cash "earnings" on financial statements is substantial.

[a] Two Components of AFUDC "Earnings"

The financing required for plant construction comes from external sources (such as bank loans, long-term debt, and preferred and common stock sales) and from internal sources (such as earnings retained by the utility). Over a given period, financing may come from any one or all of these categories. Bank loans, debt, and preferred stock reflect stated cost rates, and the costs for these sources are subject to fairly precise determination when they are adjusted to recognize related premiums, discounts, and costs of issuance.

Common equity funds (common stock and retained earnings), however, have no such convenient reference point, and, while these funds obviously do have an economic cost, the difficulties inherent in measuring their cost create considerable controversy. (See *Chapter 9* for a detailed discussion.) In addition, the AFUDC income credit related to the use of either preferred stock or common equity has the appearance of creating income, since the costs related to these capital components are not reflected in the income statement—the income credit has no counterbalancing expense to offset its effect. In contrast, debt financing involves interest costs which are shown as an expense and offset by the debt portion of the AFUDC credit, with no net effect being seen in net income. Under GAAP, it is appropriate to recognize the equity portion of the AFUDC credit in the income statement to recognize that the regulator is providing for the costs of preferred and common equity used in construction, as long as the recovery in future rates of the capitalized AFUDC is probable.

[b] Mechanics of Computation

The mechanics of computing AFUDC may vary significantly among regulatory jurisdictions and even among individual utilities within the same jurisdiction. These variations sometimes involve the methods used in determining the AFUDC capitalization (accrual) rate and in many cases involve the specific capitalization policies followed by the individual utilities. For instance, capitalization policies commonly vary as to the dollar limits and length of construction periods required before AFUDC is capitalized and also differ in the mechanics of actual capitalization (simple annual interest, interest compounded monthly, semiannually, etc.). Regulatory commissions generally must approve the specific AFUDC accrual rates and capitalization policies and also require prior approval before utilities implement any changes that have the potential to alter significantly the amount of AFUDC capitalized.

By developing a standard method for determining the maximum allowable accrual rate, the FERC has lent a certain degree of uniformity to the AFUDC capitalization process. The formula, which the FERC provided for in its Order No. 561, is as follows (see *§ 4.05*, below) for the actual wording of the formula and the accompanying instructions under FERC Uniform System of Accounts for Class A and B Electric Utilities):

A_i = s(S/W) + d(D/D + P + C) (1 − S/W)

A_e = [1 − S/W] [p(P/D + P + C) + c(C/D + P + C)]

A_i = gross allowance for borrowed funds used during construction rate
A_e = allowance for other funds used during construction rate
S = average short-term debt
s = short-term debt interest rate
D = long-term debt
d = long-term debt interest rate
P = preferred stock
p = preferred stock cost rate
C = common equity
c = common equity cost rate
W = average balance in CWIP plus nuclear fuel in process of refinement, conversion, enrichment, and fabrication

FERC Order No. 561 (and the FERC Uniform System of Accounts) expands upon the mechanics of applying the formula with the following additional instructions:

(1) Balances for long-term debt, preferred stock, and common equity shall be actual book balances as of the end of the prior year.

(2) Cost rates for long-term debt and preferred stock shall be weighted average cost.

(3) The cost rate for common equity shall be the rate granted on common equity in the last rate proceeding before the ratemaking body having primary rate jurisdiction. If such cost is not available, the average rate actually earned in the preceding three years shall be used.

(4) Short-term debt balances, short-term debt costs, and average CWIP shall be estimated for the current year and adjusted as actual data become available. No adjustment is necessary if the actual cost rate does not exceed the estimated rate by more than a fourth of one percent.

(5) Rates under the formula shall be determined annually and reported to the FERC.

A brief analysis of the FERC formula and its instructions reveals several important points. First, the formula assumes that a utility's short-term debt is the first source of funds used for financing construction. The remainder of the construction is assumed to be financed out of long-term debt, preferred stock, and common stock equity on the basis of these funds as they existed at the end of the prior year. Second, the formula provides for a precise segregation of AFUDC into its two component parts—borrowed funds and equity funds. For financial reporting purposes, the borrowed funds (debt) portion is commonly treated as a negative component of interest expense and located in the interest charges section of the income statement. The other funds portion (common equity and preferred stock) is treated as non-operating income and located in the other income and deductions section of the income statement.

In response to a request filed with FERC by EEI, AGA, and INGAA, on June 30, 2020 FERC granted a 12-month waiver request to modify the Short-term debt component of the FERC's prescribed AFUDC calculation. This will allow companies to use a simple average of prior year short-term debt balances in the calculation of the short-term debt component of AFUDC, instead of the current short-term debt balances required by the rules, while leaving all other aspects of the AFUDC rate formula unchanged (including current period short-term debt cost rates). This will allow companies to obtain the needed liquidity to respond to the COVID 19 pandemic without an unduly adverse impact on its AFUDC rate. This waiver is available to all jurisdictional entities subject to the FERC's accounting regulations and begins March 1, 2020 through February 28, 2021.

Before the Tax Reform Act of 1986 and the accompanying changes in the tax deductibility of CWIP-related interest, three basic alternatives were commonly utilized for recognizing the income tax effects of capitalized debt costs. The first two methods described below provided for the normalization of the benefits of deferred taxes, while the third approach provided for a direct flow-through of the tax benefits to the utility ratepayers.

(1) *Gross rate with normalization*. Under this alternative, the utility employed the gross rate during the computation of the debt portion of AFUDC and then provided deferred taxes on the book/tax timing difference resulting from the AFUDC credit by charging deferred income tax expense on the income statement (above-the-line) and crediting accumulated deferred income taxes on the balance sheet.

(2) *Net rate with tax allocation*. With this method, the utility initially computed a net of tax AFUDC accrual rate for use in the capitalization calculations. In this case, it was necessary to allocate properly the income tax benefit associated with AFUDC below-the-line. The net effect of this approach is similar to the gross rate approach except that the tax effect related to AFUDC is netted against the property accounts on the balance sheet. With the adoption of ASC 740, the net-of-tax approach is no longer permitted in GAAP based financial statements.

(3) *Gross rate with flow-through*. In this case, the utility used a gross accrual rate for the computation of the debt portion of AFUDC, and tax benefits were flowed through currently.

Failure to properly consider and classify the tax effects of the borrowed funds portion of AFUDC has been a major problem in accounting for capitalized financing costs. It must be remembered that the purpose of capitalizing AFUDC is not only to record the total costs of construction accurately but also to shield the utility operations (above-the-line) from the impact of these costs. In order to isolate utility operations successfully, all items related to construction must be segregated, so that utility operations can be reported as though the construction activities do not exist.

Many utilities and regulators have not been completely successful in isolating the costs of operations from the costs of construction, since they have failed to allocate properly the income tax savings from AFUDC that arise from construction activities. A failure to understand the implications of these book/tax timing differences may result in the recording of tax savings in a manner that reduces the taxes on operating income and thus affects the rate of return reported on utility operations. The income tax implications of AFUDC accounting are dealt with in greater detail in Chapter 17.

A special situation arises in cases where restricted-use debt is issued by a utility to finance the construction of facilities that are generally non-income-producing and are often associated with environmental requirements (e.g., industrial development bonds and pollution control bonds). Three characteristics distinguish these financings from capital traditionally raised by a utility to finance its construction:

(1) Use of the funds borrowed is restricted to the costs of the specific project, and any excess proceeds from the debt issuance are used to satisfy the related debt service requirements.

(2) Interest paid on the borrowings is tax exempt, which generally allows the utility to borrow the funds at a lower cost than the current rate for long-term debt.

(3) The proceeds of the borrowings are held in trust or special funds until needed, and unexpended funds are invested to earn interest income.

The central issue arising when restricted-use debt is issued is how to account for the interest earned on the unexpended funds because it affects the capitalization of AFUDC. A variety of approaches were being followed, including:

(1) reflecting the earnings in the calculation of the AFUDC rate;

(2) crediting the earnings against the CWIP financed by the restricted-use debt;

(3) lowering the cost of the long-term debt in the capital structure to reflect a “net” interest expense (i.e., the rate of return is affected, but not AFUDC); and

(4) recognizing the earnings currently in the income statement.

As a result of the divergent practices, the FERC, in 1983, issued Accounting Release AR-13 to provide for consistent treatment. Generally, AR-13 requires that restricted-use debt be included with other debt and that the average balance of the unexpended funds held in trust (or other special funds) be included in the computation of average CWIP when calculating AFUDC rates. Also, AFUDC should be capitalized on a CWIP balance that includes the unused funds balance. All earnings on the unused funds during construction are then credited to the cost of constructing the related facilities. (See *§ 4.06*, below, for the complete text of Accounting Release AR-13.)

[6] Plant Held for Future Use (PHFU)

As distinguished from CWIP, PHFU either represents plant acquired and basically ready for use in the utility function under a definite plan or land and land rights owned and held for future use. With the exception of land and land rights, PHFU is similar to the category of fixed assets known as "completed construction not classified," and no AFUDC is normally capitalized on PHFU. For this reason, assets falling in the PHFU category are generally segregated and accounted for separately. For instance, the FERC requires electric utilities to account for these assets in Account 105—Electric Plant Held for Future Use.

Considerable disagreement exists over the proper treatment of PHFU for ratemaking purposes. On one hand, it appears appropriate to include PHFU in the rate base and to permit the utility to earn a return on property that has been prudently acquired and set aside for future operations (particularly since AFUDC is normally not allowed). On the other hand, ratepayers do not relish the idea of paying the carrying costs for assets that are not presently providing any service. The most common argument offered by commissions rejecting rate base treatment for PHFU is that only plant presently used and useful in providing service should be allowed in the rate base.

A number of regulatory commissions have, however, from time to time allowed portions of PHFU in the rate base for a variety of reasons. The two general criteria for allowing rate base treatment are the following:

(1) *Imminent use*. The utility is able to demonstrate that certain PHFU will be used and useful within a short period of time.

(2) *Definite plan for use*. The utility is able to demonstrate that the purchase of certain PHFU is associated with a definite plan for use in the foreseeable future and will result in benefits to ratepayers.

The "imminent use" criterion is most clearly demonstrated where the subject PHFU is actually in service before the rate order or will be in the immediate future. On the other hand, the "definite plan for use" criterion is usually more difficult to prove, since the time frame generally extends further into the future. An important question raised in this respect is what period into the future constitutes a definite plan. While there is no clear-cut trend in this area, several commissions allowing PHFU in the rate base under the definite plan criterion have used three years as an upper limit for a definite plan.[21]

In addition to the general criteria described above, some regulatory authorities consider other factors before allowing PHFU in the rate base. The various circumstances sometimes resulting in rate base treatment include:

(1) *Environmental factors*. Environmental restrictions (safety, aesthetics, etc.) on site locations for new construction have sometimes required utilities to purchase several potential land sites well in advance. The extended time frame is necessary in order to perform required environmental studies and to obtain the required regulatory approvals, with the purchase of several potential sites considered necessary to reduce the possibility that no site will be available due to a failure to pass environmental tests. In these situations, commissions sometimes extend the time frame of the definite plan and allow the various land purchases in the rate base as prudent purchases under the circumstances. When allowed in the rate base, any gains on the subsequent sales of alternative sites may be passed on to the ratepayers, while any transfers to nonutility operations are closely scrutinized as to their ultimate disposition.

(2) *Economic factors*. Overall economic conditions or specific conditions in the area where a utility operates may make it prudent to invest in land in order to secure future plant sites. This may well be the case where land is extremely scarce (especially for urban utilities) and/or when the price of real estate is

[21] *Re Northwestern Bell Tel Co, 3 PUR 4th 486 (SD 1974)*; *Re Florida Power and Light, 9 PUR 4th 146 (Fla 1975)*; *Re* Pacific Tel and Tel Co, 58 PUR3d 229 (Cal 1965).

> steadily increasing. Under these situations, some commissions deem these land purchases as good management decisions for the benefit of ratepayers and thus allow rate base treatment. Again, the treatment of gain or loss from any subsequent sale or transfer of the property may take into consideration whether ratepayers have previously paid a return on these investments.

Many state commissions as well as FERC have policies allowing certain portions of PHFU in the rate base under various circumstances.

[7] Customer Advances for Construction/Contributions in Aid of Construction

Customer advances for construction are distinguished from contributions in aid of construction in that the former involves a recorded liability representing the obligation to eventually return the funds advanced. Little controversy exists over the fact that the liability associated with customer advances should be deducted from the rate base. The utility plant constructed with these funds is not financed with debt or equity; ratepayers should not, therefore, be obligated to pay a return on these plant investments.

A question does arise regarding appropriate ratemaking treatment if the utility pays interest on customer advances. Two basic options are available, both of which provide for appropriate consideration of the interest costs. First, customer advances can be treated similar to any other form of debt financing. In this case, the liability associated with these advances is included in the capital structure for purposes of computing the rate of return allowed on the rate base, and no reduction from the rate base is made for the customer advances liability balance. The other option is to continue to reduce the rate base for customer advances while treating the interest expense associated with these borrowings as a component of cost of service.

Ratemaking treatment for contributions in aid of construction is a different situation, because no obligation exists for the utility either to repay any funds received or to reimburse parties donating physical property. The general rule is that any such contributions should be excluded from the rate base, since the related plant investment has not been financed by the utility, and customers should not therefore be required to pay a return on the plant. The actual process of reducing the rate base for these contributions varies from one regulatory jurisdiction to another. The FERC and most state commissions now require utilities to reduce initially the plant account balances to which contributions from customers relate by the actual amount of the contribution. On the other hand, many water and wastewater utilities follow the practice (formerly followed by most utilities) of recording a contribution in aid of construction “liability” when the contribution is first received. In this case, all plant (including that constructed with contributions) is included in the rate base which in turn is generally reduced by the contribution’s “liability.”

Where utilities still record a contribution’s liability, the question is raised regarding ratemaking treatment of depreciation expense associated with plant supported by contributions. In these situations, the ruling factor appears to be the regulatory commission’s view as to the appropriate role of depreciation accounting in utility ratemaking—whether the purpose of depreciation is to provide funds for the eventual replacement of plant used by customers or whether depreciation is designed simply to enable a utility to recoup its investment in plant over the period in which it provides customers with service. Those jurisdictions that take the former view are much more likely to allow depreciation on contributed plant as an operating expense. Here, the fact that the utility did not make an investment in the plant is basically viewed as irrelevant. The utility must eventually replace this plant which customers are using, and the ratepayers are therefore obligated to provide funds for this replacement. Those jurisdictions taking the latter view clearly see no reason to allow depreciation as a component of cost of service, since the utility has no investment to recoup for plant contributed by others.

If cost of service treatment is allowed for depreciation of contributed plant, it is generally accomplished by depreciating gross plant with no amortization of the contribution-related liability. In effect, contributions are treated as permanent capital contributed by customers. Where cost of service treatment is not allowed for this depreciation, the accounting generally involves depreciation of gross plant with an offsetting amortization of the contribution’s liability to operating revenues.

[8] Operating Reserves

In some situations, regulatory commissions allow annual operating expense provisions for the purpose of creating “reserves” for either future extraordinary loss contingencies or significant future expenditures that can be anticipated to occur but for which actual future amounts can only be estimated. When actual losses or expenditures are experienced, they are applied against available reserves to the extent possible. The purpose of creating these reserves is basically twofold:

(1) In the case of extraordinary loss contingencies, operating reserves avoid placing the entire burden of the loss on rate payers at the time of occurrence (or placing the burden on future ratepayers).

(2) In the case of significant known future expenditures, reserves represent an attempt to require customers to pay all costs associated with providing their current service, a portion of which will not actually be incurred by the utility until sometime in the future.

An example of operating reserves for use against significant future expenditures relates to two interrelated types of future expenditures—nuclear plant decommissioning costs and the costs of handling and storing spent nuclear fuel. In the case of future costs for decommissioning nuclear power plants, the current expense provisions in some instances have been included as a component of depreciation expense, and the reserve has been included as a part of the accumulated depreciation reserve for regulatory reporting while these reserves are classified as asset retirement obligations or regulatory liabilities under GAAP, depending on whether they represent a legal obligation. In these instances, decommissioning costs have been treated in the same manner as traditional costs of removal. On the other hand, extremely large reserves have sometimes been associated with the current provisions for future costs of handling and storing spent nuclear fuel. As nuclear fuel is amortized, its net cost balance may, in fact, become a credit balance. For this reason, the provisions and related reserves for spent fuel often have been segregated from the nuclear fuel and the accumulated amortization accounts.

While these types of operating reserves in rate base were more prevalent in the past for a variety of future costs, today it is quite common to obtain regulatory commission approval to establish a cost tracker mechanism whereby the collection of a specific surcharge included in rates from customers is used to offset defined costs incurred, or to be incurred. To the extent that surcharges collected are greater/less than the defined costs incurred, a regulatory liability/asset will be recorded in accordance with U.S. GAAP. This type of mechanism is frequently used for energy efficiency initiatives, fuel costs, storm damage costs, among others.

When expense provisions required to create reserves are allowed in cost of service, the ratepayer is supplying funds to the utility in advance of actual need. The funds so supplied are generally available to the utility for supporting its rate base investment. Thus, the accumulated reserves are deducted from the rate base to avoid customers paying a return on funds they have supplied. In a few cases, the reserves may be funded by the utility with the money set aside for payment of the future expenditures. Under these circumstances, the utility does not have access to the funds for general operating purposes, and earnings on the funds are considered in establishing the required provision. Therefore, funded reserves do not require rate base exclusion.

[9] Deferred Income Tax Liabilities

Differences in accounting and taxable income occur for a variety of reasons, some of which involve permanent differences and some of which involve temporary differences that will reverse in subsequent years. In the case of utilities, the major component of annual temporary differences generally involves liberalized depreciation and accelerated amortization for income tax purposes. While GAAP (primarily under ASC 740) call for deferred income tax accounting for these and other temporary differences, utilities follow deferral accounting for income statement purposes only to the extent that the effects of deferred income taxes are considered as a component of cost of service for ratemaking purposes (i.e., the accounting treatment tracks the ratemaking treatment and, if tax benefits flow through to rates, financial reporting reflects this). In this respect, deferred income tax accounting (tax normalization) for utilities generally results in a larger initial book income tax provision than actual taxes payable largely as a result of items such as accelerated tax depreciation. The book provision for income taxes that exceed the amounts currently due and payable permits the utility to collect rates from its customers in the early years of a plant's life that provide more cash than is required to pay current taxes. This condition will reverse in later years when book deductions exceed tax deductions.

Considerable controversy exists over the notion of deferred income tax accounting, since it does, in fact, enable utilities to collect more from ratepayers than is currently owed to the U.S. Treasury in the form of taxes in the earlier years of a facility. If it is assumed that construction programs will increase indefinitely, the result will be a continuous net tax return deduction for depreciation and amortization in excess of related current book deductions (even though the depreciation expense on significant amounts of older property has actually reversed). This continuous situation of book tax expense in excess of taxes payable has led many consumer advocates to label deferred income taxes as “phantom” taxes that the utility will never pay.

On the other hand, the benefits of individual accelerated tax deductions do turn around, and utilities find themselves paying more tax dollars on specific items than they are collecting from their customers in rates. Thus, deferred income tax liability balances represent a genuine obligation to pay taxes at some point in the future. If customers are to shoulder the total expenses incurred in rendering their specific service, they have an obligation to pay for the income tax expenses when the liability initially arises.

The general trend has been for commissions to recognize deferred income tax accounting for more and more specific book/tax timing differences. This trend is to a large degree a consequence of the Internal Revenue Code requirement of tax normalization for ratemaking and financial reporting with respect to accelerated depreciation and investment tax credits (discussed in *§ 4.04[10]*, below). Failure to follow the normalization as prescribed by the Code results in the possible loss of eligibility to utilize the tax benefits.

The subject of deferred income taxes and related Internal Revenue Code requirements is dealt with in much greater detail in *Chapter 17*. The concern here relates to the appropriate treatment of deferred tax liabilities for rate base purposes. The general view in this respect is that these liabilities represent a source of interest-free funds supplied by the U.S. Treasury that the utility is free to use in support of rate base investment. Therefore, the rate base must be reduced by accumulated deferred income tax (“ADIT”) liabilities balance to avoid paying a return on funds that are cost free.

An optional method of recognizing the cost-free nature of the ADIT liabilities balance is to treat the liabilities as an element of the capital structure with a zero capital cost rate for purposes of determining the overall allowed rate of return on the rate base. If this method is utilized, there is no rate base reduction for the ADIT liabilities balance. Either this method or direct rate base reduction normally produces similar revenue requirements. While rate base reduction results in a higher rate of return on a lower rate base, the zero capital cost method produces a larger rate base balance with a lower rate of return requirement, with the changes in the amounts of these two elements being approximately directly proportional. A good example of this relationship is presented in Chapter 3.

A problem that sometimes occurs involves changes in the statutory tax rates. This occurred, for example, in 1978 when the federal corporate rate decreased from 48 percent to 46 percent effective January 1, 1979. As a result, deferred income taxes that were accumulated in the past on the assumption that tax rates would remain at 48 percent will actually turn around and be paid at the lower rate. It is argued that customers have, in effect, paid more for future tax liabilities than what the actual liability will be, or, to put it another way, deferred income tax liabilities set up at 48 percent will never completely reverse.

Faced with this situation, regulatory commissions basically followed one of two alternatives. First, some believe that consumers have the right to a return of the excess funds immediately. In this case, many commissions required the amortization of the additional 2-percent tax reserve over a relatively short period of time—normally one to ten years. It was argued that the short amortization period came closer to ensuring that those ratepayers originally funding the excess liabilities would be the ones receiving the “refunds.” The alternative was to amortize the excess income tax liabilities over the remaining life of the assets initially generating the reserves. In this case, the return of the over collections was accomplished by turning the timing differences around at the original 48-percent rate at which the deferred taxes were accumulated. Those defending this alternative have cited two basic points in favor of ratable amortization over the remaining asset life:

(1) *Treasury regulations*. The Internal Revenue Code requires the amortization of deferred income tax liabilities over the lives of the related assets. A shorter amortization period, regardless of the reasons, may result in the loss of eligibility to utilize accelerated tax depreciation and amortization. (See *Chapter 17* for a detailed discussion.)

(2) *Generally accepted accounting principles*. In recognition of changes over time in effective tax rates, GAAP, as stated prior to ASC 740 in Accounting Principles Board Opinion No. 11, called for the amortization of tax “reserves” over the lives of the assets creating the “reserves” at the rates utilized

when the “reserves” were originally created. For further discussion of the changes in accounting standards for income taxes and the related ratemaking impacts, please refer to Chapter 17, Accounting for Income Taxes.

The FERC’s general position on this controversial issue was initially stated by the Federal Power Commission (FPC) in 1965 with the issuance of Accounting Release No. AR-2. The FPC’s response to the question regarding the appropriate treatment was as follows:

> “Amounts accumulated in Account 281, Accumulated Deferred Income Taxes—Accelerated Amortization, shall be credited to Account 411, Income Taxes Deferred In Prior Years—Credit, at the same rate that was originally used to defer the amounts in Account 281. Therefore, the amounts previously deferred will be fully restored to income over the appropriate estimated remaining useful life allowable for tax purposes of the related property.”

The FERC readdressed this issue in an indirect manner in 1981 with the issuance of its Order No. 144, which requires tax normalization for the tax effects of certain timing differences in rate proceedings before the Commission. Here, the FERC’s primary concern related to excessive or deficient tax reserves that were largely the result of prior flow-through treatment of tax benefits that would now turn around and be accounted for under tax normalization. While recognizing that amortization of excess reserves over the service lives of the assets was an appropriate method, the FERC stated that the most appropriate method of dealing with the 2-percent reserve excess was the subject of case-by-case determination, since other factors may also have contributed to an excessive or deficient reserve.

The Tax Reform Act of 1986 reduced the federal corporate tax rate from 46 percent to 34 percent effective July 1, 1987. In contrast to the previous 2-percent reduction, the 1986 Act specifically addressed regulatory accounting treatment of the so-called “excess” deferred income tax liabilities created by the tax rate reduction. Generally, the 1986 Act specifies that deferred income tax reserves associated with timing differences between book and tax depreciation that result from different depreciation methods and lives are “protected” deferred income tax liabilities. The identified protected liabilities must be reversed using an average tax rate assumption that effectively results in a reversal at the average tax rate at which the deferred income taxes were previously provided. (See *Chapter 17* for a more detailed discussion of the 1986 Act and the regulatory implications of the corporate tax rate reduction.)

The Omnibus Budget Reconciliation Act (OBRA’93) increased the top corporate federal tax rate from 34 percent to 35 percent effective January 1, 1993. This creates shortfalls in deferred income tax liabilities provided at 34 percent that now will have to be paid at 35 percent. OBRA’93 does not address how this shortfall is to be restored. Most regulatory commissions are addressing the issue on a case-by-case basis as rate filings are made by the utilities.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the “Act”) was signed into law. Among other provisions, the Act decreased the maximum federal corporate income tax rate from 35% to a flat 21% (which resulted in a corresponding reduction of the federal benefit of state income taxes), and modified the tax bonus depreciation allowance amounts for qualified property placed in service after September 21, 2017, and before January 1, 2023. The Act did not address the regulatory accounting treatment of the so-called “excess” or “deficient” accumulated deferred income taxes (“ADIT”) created by the tax rate reduction.

During November 2018, the FERC issued a Notice of Proposed Rulemaking, *Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes* and a Policy Statement, *Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset.* A final rule on the Notice of Proposed Rulemaking was issued as Order No. 864 in November 2019.

In order to maintain an accurate cost of service in formula transmission rates after the implementation of the Act, the FERC provided guidance for formula rates with two components: (1) preservation of rate base neutrality through the removal of excess ADIT from or addition of deficient ADIT to rate base; and (2) the return of excess ADIT to or recovery of deficient ADIT from ratepayers. Further, the FERC stated that multiple approaches to modifying rate base and adjusting income tax allowances may be just and reasonable due to the varying formats of transmission rate templates and formulas currently in use. In the final rule, FERC requires public utilities with transmission formula rates to include a mechanism in those transmission formula rates to deduct any excess accumulated deferred income taxes (ADIT) from or add any deficient ADIT to their rate bases. Public utilities with transmission formula rates are also required to incorporate a mechanism to decrease or increase their income tax allowances by any amortized excess or deficient ADIT, respectively. Finally, FERC is requiring public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually track information related to excess or deficient ADIT.

As it relates to stated transmission rates, the FERC maintained FERC Order No. 144 already contained a requirement that public utilities provide sufficient support for any related tax changes. Therefore, no further regulations were deemed necessary to address excess or deficient ADIT as a result of the Act. However, the FERC did specify that the excess or deficient ADIT should be calculated using the ADIT approved in the last public utility rate case.

The FERC also ordered public utilities to return excess ADIT using the fastest allowable method under the IRS' normalization requirements. To address the concern regarding whether or not the FERC would have sufficient information to provide transparency with respect to the impacts of the Act on ADIT, the FERC adopted a requirement to disclose the following information in the Notes to the FERC Form Financial Statements on an annual basis: (1) how any ADIT accounts were re-measured and the excess or deficient ADIT contained therein; (2) the accounting of any excess or deficient amounts in Accounts 182.3 and 254; (3) whether the excess or deficient ADIT is protected or unprotected; (4) the accounts to which the excess or deficient ADIT are amortized; and (5) the amortization period of the excess or deficient ADIT being returned or recovered through the rates.

The FERC's Policy Statement clarified the following with respect to ADIT associated with a sale or retirement of an asset:

(1) For both accounting purposes and ratemaking purposes, public utilities and natural gas companies should record the amortization of the excess and/or deficient ADIT recorded in Account 254 (Other Regulatory Liabilities) and/or Account 182.3 (Other Regulatory Assets) by recording the offsetting entries to Account 410.1. (Provision for Deferred Income Taxes, Utility Operating Income) or Account 411.1 (Provision for Deferred Income Taxes—Credit, Utility Operating Income), as required by the USofA. Further, for accounting purposes oil pipelines should adjust their ADIT balances to reflect the change in federal income tax rates with offsetting entries to the appropriate income statement account, as required by the USofA. Accordingly, oil pipeline companies will not record excess or deficient ADIT for accounting purposes.

(2) For accounting purposes, public utilities and natural gas pipelines must continue to follow the accounting guidance issued by the Chief Accountant in Docket No. AI93-5-000 with respect to changes in tax law or rates.

(3) For ratemaking purposes, a public utility or natural gas pipeline that continues to have an income tax allowance, any excess or deficient ADIT associated with an asset must continue to be amortized in rates even after the sale or retirement of that asset (unless the ADIT is transferred to the buyer). This excess or deficient ADIT will be recorded as a regulatory asset or liability and continue to be refunded to or recovered from ratepayers based on the schedule that was initially established. Similarly, for ratemaking purposes oil pipelines should keep records of excess and deficient ADIT.

(See *Chapter 17* for a more detailed discussion of the Act and the related regulatory implications.)

[10] Investment Tax Credits

Accounting and ratemaking treatment for investment tax credits (ITC) has largely been dictated by the Internal Revenue Code with a limited number of options available to utilities and their regulatory commissions. In this sense, the Code has generally attempted to require a sharing of the benefits of ITC between utility investors and utility customers. This has basically been accomplished by providing for either rate base reduction for deferred ITC balances or amortization of deferred ITC balances above-the-line as a reduction of income tax expense—both of which reduce revenue requirements to the ratepayers' benefit. Only one or the other of these procedures, however, is generally allowed, thereby allowing the utility to share in the tax savings of investment tax credit. Only in limited circumstances have both procedures been permitted simultaneously and usually most public utilities use the deferral method of accounting for ITC.

The pertinent section of the Code regarding ratemaking treatment of ITC is *IRC Section 46(f)*. Two optional methods are described under this section that are commonly labeled Options 1 and 2. Utilities must follow one of these options to avoid recapture of ITC benefits by the Service.

(1) *Option 1*. Under this option, utilities are permitted to defer the ITC utilized and amortize the deferred balance over the life of the assets giving rise to the credits. This amortization is below-the-line (to nonutility tax expense), thereby having no effect on utility cost of service. The utility, however, may reduce the rate base for the unamortized deferred ITC balance. These rate base reductions are in effect restored over the useful life of the tax credit property as the deferred balance is amortized. Option 1 is generally termed as the “ratable restoration” method, since, in essence, it allows the utility to keep the tax credit savings but does not require that the utility earn a return on those assets effectively financed by the U.S. Treasury.

(2) *Option 2*. Following this option, utilities again defer the ITC utilized. Ratemaking treatment under this option is basically the reverse of Option 1. The deferred ITC balance may be amortized above-the-line, thereby reducing the income tax component of cost of service. No rate base reduction is permitted for the unamortized ITC balance. This option is generally referred to as the “ratable flow-through” method, since it allows the utility to earn a return on the entire cost of assets generating the ITC (with no reduction for the tax savings) but at the same time permits a flow-through of the ITC benefits to customers over the life of the related assets.

At one time, a third option was available. This option provided that no restrictions applied and was commonly labeled the “immediate flow-through” method. The most common treatment under this option was to recognize the utilization of ITC as a current reduction of the income tax element of cost of service. Because there was immediate recognition of the entire benefit, no deferred investment tax credit balance existed for ratemaking or financial accounting purposes. Availability of this option was restricted before 1981 and was effectively eliminated as an option for ratemaking purposes for years after 1980 by the Economic Recovery Tax Act of 1981.

This discussion of investment tax credit has been purposely brief and devoted solely to a general discussion of the available rate base treatments. A detailed discussion of this highly controversial and complex subject is contained in *Chapter 17*, where the implications of the various options are explored in detail.

[11] Other Items

Various other items are from time to time considered by the different regulatory commissions in establishing a utility’s rate base. Both the consideration of these items and the methods of handling will vary from one regulatory commission to another, depending on commission policy and the specific circumstances involved. While these items usually have an insignificant impact on the overall rate base, in some situations their impact clearly warrants appropriate attention. This section’s purpose is not to set forth an all-inclusive list but to briefly discuss the more commonly encountered items.

[a] Standby, Auxiliary, and Reserve Equipment

As discussed briefly in *§ 4.03*, above, standby, auxiliary, and reserve equipment represent reserve capacity used only in cases of emergency or to meet maximum peak service demands. Many commissions permit rate base treatment where it can be demonstrated that this property investment is truly reserve plant for the benefit of utility customers and not simply uncommitted capacity beyond reasonable emergency requirements.

Generally, a good case for inclusion in the rate base is made where the following is demonstrated:

(1) The plant is properly maintained and capable of providing service.

(2) The plant actually contributes to the overall efficiency of operations. For example, reserve utility plant may avoid the necessity of contracting for more expensive electric power from other utilities to meet peak demands.

(3) The plant does not involve uncommitted capacity that resulted from poor management policies or actions.

The specific facts and circumstances of individual situations must be reviewed by the regulatory commissions, and a judgment must be made as to whether the questioned plant is actually used and useful in providing utility service. The appropriateness of treating genuine reserve equipment as used and useful plant was clearly demonstrated by the Indiana Public Service Commission in a 1958 rate proceeding involving the Indianapolis Water Company. In this case, the question centered around the used and useful nature of plant that was not being operated to full capacity but was designed to meet the peak demands of the public. In expressing its view on the concept of used and useful plant, the Indiana Commission stated:

> "All utilities are required, in order to properly serve the public, to provide for peak demands in the design of its utility properties. There is no evidence in this case to indicate that the petitioner has departed from sound engineering practice and has overbuilt its utility properties. A unit of property cannot be partially used and useful. A unit of property is definitely either used and useful or it is not used and useful."[22]

[b] Leasehold Improvements

Leasehold improvements represent capitalized improvements or additions to property leased from other parties. Leasehold improvements are usually considered an intangible asset. Due to the nature of these capital items, they are normally accounted for separately from utility plant owned outright, with the capitalized improvements included in "miscellaneous deferred charges." To the extent related leased properties are used in the rendering of utility service, rent expense is included as a component of cost of service. Since investments in leasehold improvements are merely additions to these leased properties, these improvements are generally accorded rate base treatment in the same manner as any other plant in service. In this respect, the amortization of these improvements is an appropriate element of cost of service, while related accumulated amortization balances must be deducted from the rate base.

While rent expense related to leased property is normally included in cost of service, the question arises as to the appropriate accounting treatment for those lease transactions that would be classified as ROU assets under GAAP. Although regulatory commissions generally have not treated ROU assets related to leases as assets for ratemaking purposes, these leases are required to be accounted for as assets for financial accounting purposes. The issue of lease accounting and the FASB's decision to require capitalization (regardless of ratemaking treatment) is discussed in *Chapter 12*.

[c] Extraordinary Retirements

Extraordinary retirements sometimes occur when a partially depreciated unit of property is retired earlier than anticipated, and the reduction in the depreciation reserve is substantially greater than the amount which has been provided during the in-service years. In these cases, the plant investment has not been adequately recovered through depreciation expense. Furthermore, the depreciation reserve will be excessively depleted if the "loss" on the retirement is immediately charged against the reserve balance. Because utilities employ the group concept of depreciation accounting, the reserve applicable to the particular group is of significance to the test of reserve adequacy. The specific groups utilized are unique to individual utilities, but they often are primary plant accounts or subaccounts. The group concept of depreciation accounting is discussed in *§ 6.04*.

These situations can be caused by several factors. For instance, significant losses in demand for service may occur due to "obsolescence" of the particular service. A good example is the demise of the streetcar system. Early retirement of plant may also be necessitated by unexpected technological advances or

[22] *Re* Indianapolis Water Co, 26 PUR3d 276 (Ind 1958).

changes in government regulations that render portions of utility plant obsolete or totally inefficient. An excellent example of technological "obsolescence" was the movement away from manufactured gas operations to natural gas facilities during the 1950s and 1960s. A final factor that may result in an extraordinary retirement is significant unexpected damage to plant that is not adequately covered by insurance and for which no operating reserve has been provided. The expectation of the replacement of plant components is usually reflected in the determination of depreciation rates, so depreciation accounting practices will be a factor considered in the determination of whether a retirement is ordinary or extraordinary.

When extraordinary losses occur, utilities often request permission to charge the loss to a deferred debit account and either amortize it over future periods or dispose of it as otherwise may be directed by the jurisdictional regulatory commission. For example, the FERC provides Account 182—"Extraordinary Property Losses," which may be used to segregate these items when permission is obtained from the Commission. The disposition of items allowed in Account 182 is up to the discretion of the FERC.

As would be expected, regulatory treatment of deferred extraordinary losses varies among regulatory bodies and is greatly influenced by the specific facts and circumstances involved. On the one hand, the utility has not been allowed to recover its investment through the depreciation process. On the other hand, the property is no longer used and useful in rendering utility service. Regulatory commissions have often excluded these loss deferrals from the rate base under the premise that the utility is not entitled to a return on property no longer in service. Exceptions have been found, however, especially in the situation where gas utilities have converted from manufactured gas to natural gas facilities. For example, in 1949, the District of Columbia Public Utilities Commission allowed Washington Gas Light to include in the rate base deferred extraordinary losses resulting from the changeover to natural gas under the premise that it was not the company's fault that depreciation provisions had been inadequate in the past. It was felt that the exclusion of this item from the rate base would deprive investors of a return on investment that was originally made to furnish utility service.[23] While not allowing Brooklyn Union Gas Company to include the unamortized balance of extraordinary retirement losses in the rate base in 1970, the New York Public Service Commission did allow the utility to earn a 6 percent "carrying charge" on the average balance of these unamortized losses. The 6-percent rate represented the overall rate of return deemed adequate when the facilities (manufactured gas plant) were initially installed. The New York Commission deemed this treatment appropriate, since shareholders should not bear the full cost of carrying the unamortized balance where the original investment was proper.[24]

While rate base treatment many times is not allowed, recovery of extraordinary retirements through a cost of service amortization is more commonplace. Amortization of these balances to utility operations is often allowed where the utility can demonstrate that, through no fault of its own, prior depreciation provisions were inadequate, and the retirement is clearly for the public's benefit. This is often the case where retired plant is replaced with more efficient equipment.

[d] Cancelled Projects

For purposes of this discussion, cancelled projects refer to the cancellation of incomplete construction project as opposed projects as opposed to the abandonment or retirement of plant that has actually been in service (discussed at *§ 4.04[11][c]*, above). These abandonments can occur for a variety of interrelated reasons including:

(1) decrease in predicted demand for future service (cancellation may be voluntary or commission ordered);

(2) government regulations that render project completion infeasible; and

(3) inability to raise the necessary capital on reasonable terms.

[23] *Re* Washington Gas Light Co, 83 PUR (NS) 4 (DC 1949).

[24] *Re* Brooklyn Union Gas Co, 87 PUR3d 119 (NY 1970).

The most prominent example of cancelled projects involves the abandonment of electric generating plant construction, as was the case with a number of nuclear power plants in the 80s and 90s.

In these situations, rate base treatment is generally denied, since the accumulated construction costs were never used and useful in providing service in the past and will not be utilized in the future. An exception to this policy exists, however. In 1980, the Louisiana Public Service Commission permitted Gulf States Utilities Company to include the unamortized cost of an abandoned nuclear project in its rate base. The Louisiana Commission based its decision on the fact that no evidence existed to show imprudence or negligence on the part of the utility in initiating the particular construction project.[25]

While rate base treatment may be denied, the question remains as to the proper method to eliminate the costs accumulated before the cancellation. Amortization to cost of service is usually allowed where the utility can demonstrate:

(1) The initial decision to develop the project was prudent and in the best interests of its customers.

(2) Factors that could not be initially foreseen have resulted in the necessity to cancel the project.

(3) The utility has taken appropriate steps both to cancel the project as soon as the course of action was found necessary and to minimize additional losses.

The FERC in Opinion No. 295 adopted a 50-50 sharing policy relating to the recovery of the costs of abandoned or cancelled construction projects by electric utilities.[26] The methodology adopted by the FERC provides that 50 percent of the incurred costs of a cancelled plant are to be amortized to cost of service over the expected life of the planned plant. The remaining incurred costs of the plant are to be written off as a loss to the utility. In the past, as specified in Order No. 49, the FERC allowed utilities to pass through abandonment costs but did not permit rate base treatment of the unrecovered investment. Under the new policy, rate base treatment is permitted on the portion of the costs recovered from ratepayers, less related deferred income taxes. According to the FERC, this ruling allows utility shareholders funding major facilities to recover a greater share of abandonment losses and reduces regulatory uncertainty.

By fixing amortization periods equal to the expected plant life—rather than allowing them to vary from case to case—the FERC hopes to avoid rate cases involving plant abandonments.

The FERC's prior policy under Opinion No. 49 permitted utilities to defer and amortize cancelled plant costs in order to recover their total investment in cancelled projects, including accrued AFUDC, up to the time of cancellation. However, utilities were not allowed to include the unamortized deferral in rate base (and thereby earn a return on the unrecovered cost during the recovery period). Electric utilities in the past have requested rate base recognition of unrecovered cancelled plant costs, and the FERC appropriately reexamined this issue.

In GAAP based financial statements, a cancelled plant or a plant that is probable of abandonment is accounted for in accordance with ASC 980-360-35-1 through 4.

[e] Customer Deposits

Customer deposits generally represent funds received from ratepayers as security against potential losses arising from failure to pay for service. These funds are similar in nature to customer advances for construction (see *§ 4.04[7]*, above). Both represent a liability to repay the funds received either after a specified period or upon satisfaction of certain requirements. Like customer advances, the deposits are available to the utility for use in support of its rate base investment.

The alternative methods of treating customer deposits for ratemaking purposes also parallel treatment of customer advances. If no interest accrual is required on the funds, the deposits represent a cost-free source of capital commonly deducted from the rate base. If customer deposits are interest bearing, two options are available. The liability may be deducted from the rate base with the associated interest included

[25] *Re Gulf States Util Co, 40 PUR 4th 593 (La 1980)*.

[26] New England Power Co, FERC Release No. R-88-03, Dkt Nos ER 85-646 et seq (Jan 15, 1988).

as a component of cost of service, or the liability may be included in the capital structure for purposes of calculating the allowed rate of return (in which case there is no rate base reduction).

[f] Merchandising Property

As a general rule, merchandising property is excluded from the rate base, because it is not used and useful in rendering utility service. On rare occasions, however, commissions have made exceptions under the premise that appliance merchandising tends to promote the sale of utility services. In those cases where rate base treatment is allowed, merchandising revenue and expense are included in above-the-line operations. If inclusion in the rate base is permitted, the reasons generally cited for allowing this treatment are the following:

(1) Merchandising activities are directly connected and interrelated with rendering utility services.

(2) Personnel and property utilized in the utility function are also involved in merchandising activities; therefore, the inclusion of these activities under the ratemaking concept avoids a somewhat arbitrary allocation between utility and nonutility operations.

[12] Stranded Costs

The issue of stranded costs became a significant regulatory concern as the electric utility industry moved toward competition and deregulation. Electric utilities and their regulators recognized that costs traditionally included in the rate base were becoming stranded. This occurred because the costs were no longer economically viable due to changes in statutes or regulatory policies that allowed other parties to compete for the utility customers. The FERC has recognized the need for utilities to recover stranded costs through FERC Order No. 636 and FERC Order No. 888. FERC Order No. 636 allowed natural gas pipelines to recover from pipeline customers, prudently incurred costs that otherwise would not have been recovered because of the switch from bundled to unbundled service. FERC Order No. 888 embraces this same concept regarding open access to electric transmission and generation-related stranded costs. (Stranded costs are discussed in greater detail in *§ 20.04*.)

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Edison Electric Institute

Alternative Regulation for Evolving Utility Challenges:

An Updated Survey

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Table of Contents

I. Introduction: The Problem of Financial Attrition Under Traditional Cost of Service Regulation

Many utilities are exploring alternatives to traditional rate regulation today. The underlying problem they face is a tendency of cost to grow more rapidly than the billing determinants (*e.g.* kWh of use) that determine revenue growth between rate cases. On the cost side, some utilities need large new generation or transmission investments. Others are engaged in accelerated distribution system modernization. Even without accelerated modernization, "wireco utilities" tend to experience more rate base growth than was the norm in the last years before they sold or spun off their generation. On the revenue side, growth in energy usage per customer ("average use") helped finance utility cost growth before 1980 because it bolstered revenue appreciably more than cost. Arguably, this was a feature of the Regulatory Compact which allowed utilities to finance needed new capacity.[1] Growth in average use has been much slower since then. Few utilities have experienced much bounceback in average use since the recession thanks to sluggish economic growth, increased energy efficiency, and the spread of distributed generation ("DG"). Some utilities are experiencing declining average use.

Traditional approaches to utility regulation can fail to provide timely rate relief for such conditions. The frequency of rate cases has increased. Utilities facing a pronounced gap between cost and billing determinant growth can experience chronic underearning even with annual rate cases. Financial attrition undoubtedly has been a factor in the long-term decline of average credit ratings among investor-owned electric utilities. This is illustrated in Figure 1. Higher risk raises financing costs and can discourage needed investments.

Alternative approaches to regulation have been developed which handle today's business conditions better. Some, such as multiyear rate plans, formula rates, and fully-forecasted test years, are comprehensive in character but involve large-scale departures from traditional regulation. Others, such as revenue decoupling and cost trackers, target cost and revenue problem areas that cause cost and revenue growth to differ. Judicious use of targeted approaches can bring revenue and cost growth into better balance and reduce the frequency of rate cases.

This survey, now updated to include precedents through late 2012, briefly explains salient alternative regulation ("Altreg") options and details precedents for electric and natural gas utilities. A summary of states that currently use these approaches is featured in Table 1. Natural gas precedents are included because of their relevance to "wires only" utilities.

[1] See Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation, by Karl McDermott, June 2012. Prepared for the Edison Electric Institute.

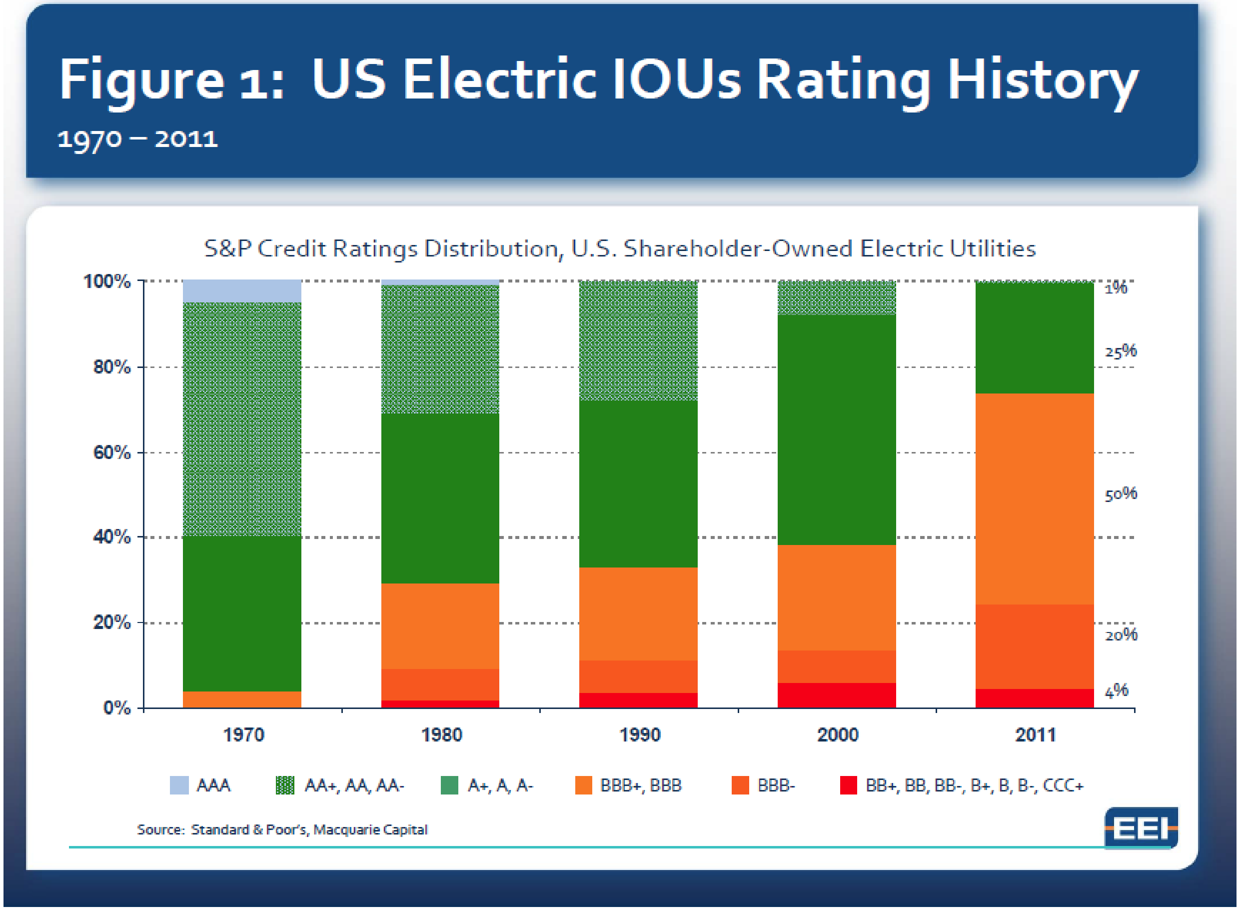


Figure 1: US Electric IOUs Rating History
1970 – 2011
S&P Credit Ratings Distribution, U.S. Shareholder-Owned Electric Utilities
100%
80%
60%
40%
20%
0%
1970
1980
1990
2000
2011
1%
25%
50%
20%
4%
AAA
AA+, AA, AA-
A+, A, A-
BBB+, BBB
BBB-
BB+, BB, BB-, B+, B, B-, CCC+
Source: Standard & Poor's, Macquarie Capital
EEI

Table 1

Innovations to Reduce Regulatory Lag: An Overview of Current Precedents

State	Capex Cost Tracker	CWIP in Rate Base[1]	Multiyear Rate Plan[2]	Revenue Decoupling			Retail Formula Rate Plans	Forward Test Years
				Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing		
Alabama	Yes						Yes	Yes
Arizona	Yes		Yes (electric only)	Yes (gas only)	Yes			
Arkansas	Yes			Yes (gas only)	Yes			
California	Yes		Yes	Yes				Yes
Colorado	Yes	Yes	Yes (electric only)					
Connecticut	Yes (electric only)			Yes (electric only)	Yes (gas only)	Yes		Yes
Delaware	Pending							
District of Columbia				Yes (electric only)				
Florida	Yes	Yes	Yes (electric only)			Yes (gas only)		Yes
Georgia	Yes	Yes	Yes (electric only)	Yes (gas only)		Yes (gas only)	Yes (gas only)	Yes
Hawaii	Yes (electric only)		Yes (electric only)	Yes (electric only)				Yes
Idaho				Yes (electric only)				
Illinois				Yes (gas only)		Yes	Yes (electric only)	Yes
Indiana	Yes (electric only)	Yes		Yes (gas only)	Yes (electric only)			
Iowa	Yes (electric only)		Yes (electric only)					
Kansas	Yes	Pending			Yes (electric only)			
Kentucky	Yes				Yes	Yes (gas only)		Yes
Louisiana	Yes (electric only)	Yes	Yes (electric only)		Yes (electric only)		Yes	Yes (electric only)
Maine	Yes (electric only)		Yes (electric only)					Yes
Maryland				Yes				
Massachusetts	Yes			Yes	Yes			
Michigan	Yes (gas only)	Pending		Yes (gas only)				Yes

Table 1 (continued)

Innovations to Reduce Regulatory Lag: An Overview of Current Precedent

State	Capex Cost Tracker	CWIP in Rate Base[1]	Multiyear Rate Cap[2]	Revenue Decoupling			Retail Formula Rate Plans	Forward Test Years
				Decoupling True Up Plans	Lost Revenue Adjustment Mechanisms	Fixed Variable Retail Pricing		
Minnesota	Yes	Yes		Yes (gas only)				Yes
Mississippi	Yes (electric only)	Yes				Yes (electric only)	Yes	Yes
Missouri	Yes (gas only)					Yes (gas only)		
Montana	Yes				Yes			
Nebraska								
Nevada				Yes (gas only)	Yes (electric only)			
New Hampshire	Yes		Yes (electric only)		Yes (electric only)			
New Jersey	Yes			Yes (gas only)				
New Mexico		Pending						Pending
New York	Yes (electric only)		Yes	Yes	Yes			Yes
North Carolina		Yes		Yes (gas only)	Yes (electric only)			
North Dakota		Pending				Yes (gas only)		Yes
Ohio	Yes	Pending	Yes (electric only)	Yes (electric only)	Yes (electric only)	Yes (gas only)		
Oklahoma	Yes (electric only)	Pending			Yes (electric only)	Yes (gas only)	Yes (gas only)	
Oregon	Yes			Yes	Yes			Yes
Pennsylvania	Yes (electric only)							Pending
Rhode Island	Yes			Yes				Yes
South Carolina	Yes (electric only)	Yes			Yes (electric only)		Yes (gas only)	
South Dakota	Yes (electric only)	Pending						
Tennessee				Yes (gas only)				Yes
Texas	Yes	Yes					Yes (gas only)	
Utah	Yes (gas only)			Yes (gas only)				Yes
Vermont	Yes (electric only)		Yes					
Virginia	Yes	Yes	Yes (electric only)	Yes (gas only)				
Washington	Pending			Yes (gas only)				
West Virginia	Yes (electric only)	Yes						
Wisconsin		Yes		Yes				Yes
Wyoming	Yes (electric only)	Yes		Yes (gas only)	Yes			Yes (electric only)

[1] This column pertains only to electric utilities.
[2] This column excludes plans involving rate freezes without extensive supplemental funding from trackers.

II. Cost Trackers and CWIP in Rate Base

A cost tracker is a mechanism for expedited recovery of specific utility costs. Balancing accounts are typically used to track unrecovered allowances. Cost recovery is often implemented using tariff sheet provisions called riders.

Trackers are used in various situations where they are a more practical means of adjusting rates for particular business conditions. Utilities usually recover fuel and purchased power costs via trackers because the volatility and substantial size of these costs would otherwise lead to frequent general rate cases and high risk. Other volatile expenses that are sometimes addressed using trackers include those for pension contributions and uncollectible bills.

A second common use of trackers is for costs that must be incurred because they are required by government agencies. Examples here include franchise fees and certain taxes. Tracking costs like these is fair to utilities and encourages government agents to moderate policies that are apt to raise customer bills.

Trackers are also widely used to compensate utilities for costs that are rapidly rising and don't produce much revenue, whether or not they are volatile or mandated. This can facilitate the targeted expenditures and reduce operating risk and rate case frequency. Examples of operation and maintenance ("O&M") expenses that are sometimes tracked due in whole or part to their rapid growth include those for health care and demand side management ("DSM").

Trackers for the costs of plant additions are sometimes called capital expenditure ("capex") trackers. The costs that are recovered typically include the accumulating depreciation, return on asset value, and taxes that the capex gives rise to. Recovery is sometimes achieved by keeping a rate case open beyond the date of a final decision for the limited purpose of adding assets to the revenue requirement.

Capex costs can qualify for expedited recovery using either or both of the second or third reasons just discussed. A utility might, for example, be compelled to make capital expenditures due to highway relocations or changes in government safety or reliability standards or conductor undergrounding requirements. Capex costs might also be tracked because they are large enough to cause material growth in assets that would otherwise occasion frequent rate cases.

The construction of base load generating capacity is a common source of major plant additions for VIEUs. This kind of capacity can take years to construct, especially when it is powered by solid fuels or hydroelectric resources. An allowance in rates for funds used during construction was traditionally not permitted until assets were used and useful and a rate case was filed. Deferred recovery can strain utility cash flow, involve extra financing expenses, and induce rate "shock" when the value of the plant and construction financing is finally added to the rate base. This is particularly true if the utility is not experiencing growth in average use during the years of construction. Many commissions address these problems by making a return on construction work in progress ("CWIP") eligible for immediate recovery. Capital cost trackers are often used in lieu of frequent rate cases to obtain CWIP recovery.

The capex costs of distribution system modernization are sometimes recovered using trackers for somewhat different reasons. The annual expenditure may not be as large as that for solid-fuel generation capacity, and construction of specific assets usually takes less than a year. However, the expenditures can still be sizable and, unlike new generation or customer connections, don't automatically trigger new revenue when construction is finished. A tracker for the cost of the new investment can help a company modernize its grid and improve its services without frequent rate cases.

The capex costs of generation emissions controls are often accorded expedited recovery for a combination of the reasons just discussed. The controls are occasioned by the emissions policies of state and federal agencies. Additionally, the facilities do not produce revenue and some facilities often become used and useful each year over a series of years.

There are varied treatments of costs in approved capex trackers. Plant addition budgets are usually set in advance and commission review of these budgets can be extensive. Once a budget is established, treatment of variances from the budget becomes an issue. Some trackers permit conventional prudence review treatment of cost overruns. In other cases, no adjustments are subsequently made if cost exceeds the budget. In between these extremes are mechanisms in which deviations, of prescribed magnitude, from budgeted amounts are shared formulaically (*e.g.* 50-50) between the utility and its customers.

Recent precedents for capital cost trackers are listed in Table 2 and Figures 2 and 3. It can be seen that the precedents are quite numerous and continue to grow. This is one of the most widespread approaches to Altreg. On the electric side, trackers for emissions controls, generation capacity, and advanced metering infrastructure have been especially common in recent years. Trackers for gas utilities often focus on the cost of replacing old cast iron and bare steel mains. Trackers for water utilities, sometimes called distribution system improvement charges ("DSICs"), are also common for accelerated modernization. Recent electric utility precedents for CWIP in rate base are listed in Table 3 and Figure 4. It can be seen that most involve investments in generating plant.

Figure 2: Recent Capex Tracker Precedents by State: Energy Utilities

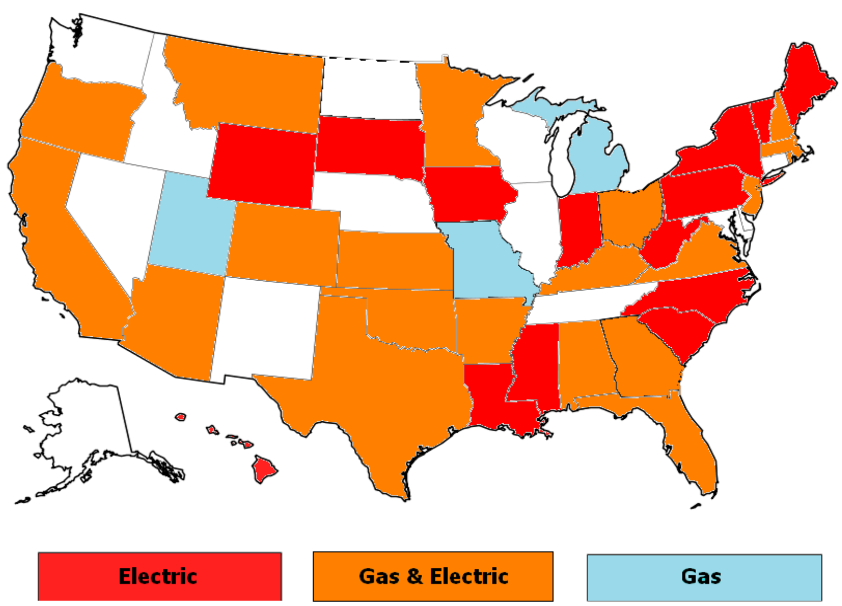


Table 2
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
			Current		
AL	Alabama Power	Electric	Rate Certificated New Plant	Any approved by Commission through CPCN	Dockets 18117 and 18416 (November 1982)
AL	Mobile Gas Service	Gas	Cast Iron Replacement Factor	Replacement of cast iron mains	Docket 24794 (November 1995)
AR	CenterPoint Energy Arkla	Gas	Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket 06-161-U (October 2007)
AR	CenterPoint Energy Arkla	Gas	Government Mandated Expenditure Surcharge Rider	Replacements resulting from highway and street rebuilding	Docket No. 10-108-U (March 2011)
AR	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Systemwide smart grid implementation	Docket No. 10-109-U (August 2011)
AR	SWEPCO	Electric	Generation Recovery Rider	New generation	Docket No. 09-008-U (November 2009)
AZ	Arizona Public Service	Electric	Environmental Improvement Surcharge	Environmental improvement projects	Docket No. E-01345A-11-024
AZ	Arizona Public Service	Electric	Renewable Energy Standard Adjustment Schedule	Renewables not recovered in base rates	Docket No. E-01345A-08-0172
AZ	Southwest Gas	Gas	Customer Owned Yard Line Cost Recovery Mechanism	Replacement and ownership of customer-owned yard lines that have been shown to be leaking	Docket No. G-01551A-10-0458 (January 2012)
CA	Pacific Gas & Electric	Electric & Gas	Smart Meter Balancing Accounts	AMI	Decision 06-07-027 (July 2006)
CA	Pacific Gas & Electric	Electric	Cornerstone Improvement Project Balancing Account	Capital and O&M expenses to improve the reliability of the electric distribution system	Decision 10-06-048 (June 2010)
CA	Pacific Gas & Electric	Gas Transmission	Pipeline Safety Implementation Plan	Pipeline replacement, automated valve installation, and upgrades to pipeline	Decision 12-12-030 (December 2012)
CA	San Diego Gas & Electric	Electric & Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 07-04-043 (April 2007)
CA	San Diego Gas & Electric	Electric	SONGS Major Additions Adjustment Clause	Steam generator replacement for San Onofre Nuclear Generating Station	Decision 06-11-026 (November 2006)
CA	Southern California Edison	Electric	Steam Generator Replacement Project	Steam generator replacement for San Onofre Nuclear Generating Station	Decision 05-12-040 (December 2005)
CA	Southern California Edison	Electric	SmartConnect Balancing Account	Advanced Metering Infrastructure Project	Decision No. 08-09-039 (September 2008)
CA	Southern California Edison	Electric	Solar PV Balancing Account	Solar generation	Decision No. 09-06-049 (June 2009)
CA	Southern California Gas	Gas	Advanced Metering Infrastructure Balancing Account	AMI	Decision 10-04-027 (April 2010)
CO	Atmos Energy	Gas	AMI Surcharge	AMI pilot deployment	Docket No. 10A-189G (May 2010)
CO	Public Service Company of Colorado	Electric	Transmission Cost Adjustment	Transmission projects	Docket No. 07A-339E, Decision No. C07-1085 (December 2007)
CO	Public Service Company of Colorado	Gas	Pipeline Safety Integrity Adjustment	Gas distribution and transmission integrity management programs, main replacement, partial recovery of two large pipeline replacements	Docket No. 10-AL-963G (August 2011)
CT	Connecticut Light & Power	Electric	System Resiliency Plan	Structural hardening	Docket No. 12-07-06 (January 2013)
DE	All utilities may file	Electric & Gas	Utility Facility Relocation Charge	Replacements due to mandated relocations that are not otherwise reimbursed	PSC Regulation Docket No. 63 (April 2012)
FL	Chesapeake Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket No. 120036-GU (September 2012)
FL	Florida Public Utilities	Gas	Gas Reliability Infrastructure Program Tariff	Replacement of bare steel mains and services	Docket No. 120036-GU (September 2012)
FL	Gulf Power	Electric	Environmental Cost Recovery Clause	Environmental	Docket No. 930613-EI (January 1994)
FL	Florida Power and Light	Electric	Environmental Cost Recovery Clause	Environmental	Docket No. 080281-EI (August 2008)
FL	Florida Power and Light	Electric	Generation Base Rate Adjustment	Generation	Docket No. 120015-EI (December 2012)
FL	Florida Power and Light	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket No. 090009-EI (November 2009)
FL	Peoples Gas System	Gas	Cast Iron/Bare Steel Replacement Rider	Replacement of bare steel and cast iron pipes	Docket No. 110320-GU (September 2012)
FL	Progress Energy Florida	Electric	Capacity Cost Recovery Clause	Nuclear power	Docket No. 090009-EI (November 2009)
FL	Progress Energy Florida	Electric	Environmental Cost Recovery Clause	Environmental	Docket No. 050078-EI (September 2005)
FL	Tampa Electric	Electric	Environmental Cost Recovery Clause	Environmental	Docket No. 960688-EI (August 1996)
GA	Atmos Energy	Gas	Pipe Replacement Surcharge	Replace cast iron and bare steel pipe	Docket No. 12509-U (December 2000)
GA	Atlanta Gas Light	Gas	Strategic Infrastructure Development and Enhancement Program	Infrastructure improvements that sustain reliability and operational flexibility	Docket No. 8516-U (October 2009)
GA	Georgia Power Company	Electric	Environmental Compliance Cost Recovery	Environmental	Docket No. 25060-U (December 2007)
GA	Georgia Power Company	Electric	Nuclear Construction Cost Recovery	Nuclear generation	Docket No. 27800, Senate Bill 31

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
HI	Hawaii Electric Light	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket No. 2007-0416 (December 2009)
HI	Hawaiian Electric Company	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket No. 2007-0416 (December 2009)
HI	Maui Electric	Electric	Renewable Energy Infrastructure Program Surcharge	Renewable energy infrastructure	Docket No. 2007-0416 (December 2009)
IA	MidAmerican Energy	Electric	Cooper Tracking Mechanism	Nuclear plant	Docket APP-96-1 (June 1997), Docket No. TF-02-154 (APP-96-1, RPU-96-8) (May 2002)
IN	Duke Energy Indiana	Electric	Qualified Pollution Control Property	Environmental	Cause No. 41744 (February 2001)
IN	Duke Energy Indiana	Electric	Integrated Coal Gasification Combined Cycle Generating Facility Cost Recovery Adjustment	Integrated gasification combined cycle generating plant	Docket No. 43114 (November 2007)
IN	Indianapolis Power & Light	Electric	Environmental Compliance Cost Recovery	Environmental	Cause 42170 (November 2002)
IN	Indiana Michigan Power	Electric	Clean Coal Technology Rider	Environmental	Cause No. 43636 (June 2009)
IN	Northern Indiana Public Service	Electric	Environmental Cost Recovery Mechanism	Environmental	Cause No. 42150 (November 2002)
KS	Atmos Energy	Gas	Gas System Reliability Surcharge	Infrastructure system replacements	Docket No. 10-ATMG-133-TAR (December 2009)
KS	Black Hills Energy (Aquila)	Gas	Gas System Reliability Surcharge	Infrastructure system replacements	Docket No. 07-AQLG-431-RTS (May 2007)
KS	Kansas Gas Service	Gas	Gas System Reliability Surcharge	Infrastructure system replacements	Docket 10-KGSG-155-TAR (December 2009)
KS	Kansas Gas & Electric	Electric	Environmental Cost Recovery Rider	Environmental	Docket No. 05-WSEE-981-RTS (October 2005)
KS	Midwest Energy	Gas	Gas System Reliability Surcharge	Infrastructure system replacements	Docket 09-MDWE-722-TAR (May 2009)
KS	Westar Energy Inc.	Electric	Environmental Cost Recovery Rider	Environmental	Docket No. 05-WSEE-981-RTS (October 2005)
KY	Atmos Energy	Gas	Pipe Replacement Program Rider	Replacement of bare steel service lines, curb valves, meter loops, and mandated relocates	Docket No. 2009-00354 (May 2010)
KY	Columbia Gas	Gas	Advanced Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket No. 2009-00141 (September 2009)
KY	Delta Natural Gas	Gas	Pipe Replacement Program Surcharge	Replacement of bare steel pipe, service lines, curb valves, meter loops, and mandated pipe relocations	Case No. 2010-00116 (October 2010)
KY	Kentucky Power	Electric	Environmental Cost Recovery Surcharge	Environmental	Docket No. 2002-00169 (March 2003)
KY	Kentucky Utilities	Electric	Environmental Cost Recovery Surcharge	Environmental	Case No. 93-465 (July 1994)
KY	Louisville Gas & Electric	Electric	Environmental Cost Recovery Surcharge	Environmental	Case No. 94-332 (April 1995)
KY	Louisville Gas & Electric	Gas	Gas Line Tracker	Replacement and transfer of ownership of customer owned service risers	Case No. 2012-00222 (December 2012)
LA	Cleco Power	Electric	Infrastructure and Incremental Costs Recovery	Generation, Transmission, environmental, other projects to be determined	Docket U-30689 (October 2010)
MA	Bay State Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel mains and services	DPU 09-30
MA	Massachusetts Electric	Electric	Net CapEx Factor	All distribution above depreciation expense	DPU 09-39
MA	Massachusetts Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	Nantucket Electric	Electric	Solar Cost Adjustment Provision	Solar generation	DPU 09-38
MA	National Grid (Boston-Essex Gas and Colonial Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of bare steel, cast iron, and wrought iron mains, services, meters, meter installations, and house regulators	DPU 10-55
MA	New England Gas	Gas	Targeted Infrastructure Recovery Factor	Replacement of non-cathodically protected steel mains and services and small diameter cast-iron and wrought iron	DPU 10-114
MA	NSTAR Electric	Electric	Capital Projects Scheduling List	Stray voltage inspection survey and remediation program; double pole inspections, replacements, and restorations; and manhole inspection, repair, and upgrade	DTE 05-85 and DPU 10-70-B
MA	NSTAR Electric	Electric	NA	Smart grid pilot	DPU-09-33
MA	Western Massachusetts Electric	Electric	Solar Program Cost Adjustment	Solar generation	DPU 09-05
MN	Minnesota Power	Electric	Arrowhead Regional Emission Abatement Rider	Environmental	M-05-1678 (June 2006)
MN	Minnesota Power	Electric	Renewable Resource Rider	Renewable generation	Docket M-10-273 (July 2010)
MN	Minnesota Power	Electric	Transmission Cost Recovery Rider	Incremental transmission investment	Docket M-07-965 (December 2007)
MN	Northern States Power (Xcel Energy)	Electric	Renewable Energy Standard Cost Recovery Rider	Renewable generation	M-07-872 (March 2008)
MN	Northern States Power (Xcel Energy)	Electric	Metropolitan Emissions Reduction Project (later called Environmental Improvement Rider)	Environmental	Docket M-02-633 (March 2004)
MN	Northern States Power (Xcel Energy)	Electric	Mercury Cost Recovery Rider	Environmental	Docket No. M-09-847 (November 2009)
MN	Northern States Power (Xcel Energy)	Gas	State Energy Policy Rider	Cast iron replacements	Docket No. M-08-261 (November 2008)

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
ME	Central Maine Power	Electric	NA	AMI	Docket No. 2007-215(II) (February 2010)
MI	SEMCO Gas	Gas	Main Replacement Rider	Replacement of cast iron and unprotected steel mains and service lines	Case U-16169 (January 2011)
MO	AmerenUE	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components	Case No. GT-2008-0184 (February 2008)
MO	Atmos Energy	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components	Docket No. GO-2009-0046 (October 2008)
MO	Laclede Gas	Gas	Infrastructure System Replacement Surcharge	Replacement of mains, valves, service lines, regulator stations, vaults, other pipeline components	Docket No. GR-2007-0208 (July 2007)
MO	Missouri Gas Energy	Gas	Infrastructure System Replacement Surcharge	Natural gas line replacements and relocations	Docket No. GR-2009-0355 (February 2010)
MS	Mississippi Power	Electric	Enviromental Compliance Overview Plan Rate	Environmental	Docket No. 92-UA-0058 and 92-UN-0059 (July 1992)
MT	Northwestern Energy	Electric	NA - Amounts recovered through electric supply service rates	Generation	Docket D.2008.6.69 (November 2008)
MT	Northwestern Energy	Gas	Natural Gas Supply Tracker	Battle Creek natural gas production resources	Docket No. D2012.3.25 (November 2012)
NH	Energy North	Gas	Cast Iron/Bare Steel Replacement Program	Replacement of cast iron and bare steel pipe	Docket DG-107 (June 2007)
NH	Granite State Electric	Electric	Reliability Enhancement Plan Capital Investment Allowance	Feeder hardening and asset replacement	Docket DG-107 (June 2007)
NH	Public Service Company of New Hampshire	Electric	Energy Service	Environmental	DE 11-250 (April 2012)
NJ	Elizabethtown Gas	Gas	Utility Infrastructure Enhancement Rate	Projects to enhance reliability and reinforce infrastructure	Docket No. GO09010053 (April 2009)
NJ	Elizabethtown Gas	Gas	Utility Infrastructure Enhancement Rate II	Projects to enhance reliability and reinforce infrastructure	Docket No. GO10120969 (May 2011)
NJ	New Jersey Natural Gas	Gas	Compressed Natural Gas Pilot Program	Compressed natural gas infrastructure	Docket No. GR11060361 (June 2012)
NJ	Public Service Electric and Gas	Electric & Gas	Capital Infrastructure Investment Program	Electric: reliability upgrades & feeder replacement, Gas: replacement of cast iron & bare steel mains and services	Docket No. GO09010050 (April 2009)
NJ	Public Service Electric and Gas	Electric & Gas	Capital Infrastructure Investment Program II	Electric: reliability upgrades & feeder replacement, Gas: replacement of cast iron & bare steel mains and services	Docket No. EO11020088, GO10110862 (July 2011)
NJ	Public Service Electric and Gas	Electric	Solar Generation Investment Program	Solar generation	Docket No., EO09020125 (August 2009)
NJ	Rockland Electric	Electric	Smart Grid Surcharge	Smart Grid pilot	Docket No. EO09060459 (April 2010)
NJ	South Jersey Gas	Gas	Capital Investment Recovery Tracker	Bare steel replacement, expand key distribution mains for reliability	Docket No. GO09010051 (April 2009)
NJ	South Jersey Gas	Gas	Capital Investment Recovery Tracker II	Bare steel replacement, expand key distribution mains for reliability	Docket No. GO10100765 (March 2011)
NJ	South Jersey Gas	Gas	Capital Investment Recovery Tracker III	Accelerated Main Replacement Program	Docket No. GO11100632 (May 2012)
NY	Consolidated Edison	Electric	Monthly Adjustment Clause	AMI, SCADA, undergrounding	Case 09-E-0310 (October 2010)
OH	Cleveland Electric Illuminating	Electric	Rider AMI	Ohio Site Deployment	Case Nos. 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Cleveland Electric Illuminating	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case	Case No. 10-388-EL-SSO (August 2010)
OH	Columbia Gas of Ohio	Gas	Infrastructure Replacement Program Rider	Replacement of cast iron and bare steel mains & services, AMI	Case No. 08-0072-GA-AIR, 08-0073-GA-ALT, 08-0074-GA-AAM, and 08-0075-GA-AAM (December 2008); Case No. 09-1036-GA-RDR (April 2010)
OH	Columbus Southern Power	Electric	Distribution Investment Rider	Net capital additions since the date certain of most recent rate case not recovered through other riders	Case 11-346-EL-SSO
OH	Columbus Southern Power	Electric	GridSMART Rider (Phase I)	Smart grid	Case No. 08-917-EL-SSO and 08-918-EL-SSO (March 2009)
OH	Dayton Power and Light	Electric	Environmental Investment Rider	Environmental	Case No. 05-276-EL-AIR (December 2005)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Pipeline Infrastructure Replacement Rider	Pipelines & faulty riser replacements	Case No. 09-458-GA-RDR (December 2009)
OH	East Ohio Gas d/b/a Dominion East Ohio	Gas	Automated Meter Reading Charge	AMI	Case No. 07-0829-GA-AIR, 07-0830-GA-ALT, 07-0831-GA-AAM, 08-0169-GA-ALT, and 06-1453-GA-UNC (October 2008); Case No. 09-38-GA-UNC (May 2009); Case No. 09-1875-GA-RDR (May 2010)

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
OH	Duke Energy Ohio	Gas	Accelerated Main Replacement Program Rider	Replacement of bare steel and cast iron mains and services	Case No. 01-1228-GA-AIR, and 01-1478-GA-ALT, and 01-1539-GA-AAM (May 2002); 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Gas	Advanced Utility Rider	Gas AMI	Case No. 07-0589-GA-AIR 07-0590-GA-ALT 07-0591-GA-AAM (May 2008)
OH	Duke Energy Ohio	Electric	Infrastructure Modernization Distribution Rider	Electric AMI	Case No. 08-920-EL-SSO and 08-921-EL-AAM and 08-922-EL-UNC and 08-923-EL-ATA (December 2008)
OH	Ohio Edison	Electric	Rider AMI	Ohio Site Deployment	Case Nos. 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Ohio Edison	Electric	Delivery Capital Recovery Rider	Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case No. 10-388-EL-SSO (August 2010)
OH	Ohio Power	Electric	Distribution Investment Rider	Net capital additions since the date certain of most recent rate case not recovered through other riders	Case 11-346-EL-SSO
OH	Ohio Power	Electric	GridSMART Rider (Phase I)	Smart grid	Case No. 08-917-EL-SSO and 08-918-EL-SSO (March 2009)
OH	Toledo Edison	Electric	Rider AMI	Ohio Site Deployment	Case Nos. 09-1820-EL-ATA and 12-1230-EL-SSO
OH	Toledo Edison	Electric	Delivery Capital Recovery Rider	Power Distribution, subtransmission, general, and intangible plant not included in most recent rate case (filed in 2007)	Case No. 10-388-EL-SSO (August 2010)
OH	Vectren Energy Delivery	Gas	Distribution Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket No. 07-1081-GA-ALT, 07-1080-GA-AIR and 08-0632-GA-AAM (January 2009)
OK	Oklahoma Gas & Electric	Electric	Smart Grid Rider	Smart grid	Cause No. PUD 201000029 (July 2010)
OK	Oklahoma Gas & Electric	Electric	System Hardening Recovery Rider	Undergrounding and other circuit hardening	Cause No. PUD 20080387, Order No. 567670 (May 2009)
OK	Oklahoma Gas & Electric	Electric	Crossroads Rider	Crossroads Wind Farm	Cause No. PUD 201000037 (July 2010)
OK	Public Service Company of Oklahoma	Electric	Reliability Vegetation/Undergrounding Rider	Conversion of overhead to underground customer service lines	Cause No. PUD 200800144 (January 2009)
OR	Northwest Natural Gas	Gas	System Integrity Program	Bare steel replacement, Transmission integrity management program, distribution integrity management program	Docket UM 1406, Order No. 09-067 (March 2009)
OR	PacifiCorp	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
OR	PacifiCorp	Electric	NA	Mona to Oquirrh transmission line only if line is placed into service within 6 months of May 31, 2013	Docket UE 246, Order 12-493 (December 2012)
OR	Portland General Electric	Electric	Renewable Adjustment Clause	Renewable generation	Docket UM 1330 (December 2007)
PA	All utilities may file	Electric & Gas	Distribution System Improvement Charge	Non-expense reducing, non-revenue producing infrastructure replacement projects	Docket No. M-2012-2293611 (August 2012)
PA	PPL Electric Utilities	Electric	Act 129 Compliance Rider	AMI	Docket No. M-2009-2123945 (January 2010)
PA	PECO	Electric	Smart Meter Cost Recovery Rider	AMI	Docket No. M-2009-2123944 (April 2010)
PA	Metropolitan Edison	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Electric	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Pennsylvania Power	Electric	Smart Meters Technologies Charge	AMI	Docket M-2009-2123950 (April 2010)
PA	Duquesne Light	Electric	Smart Meter Charge Rider	AMI	Docket No. M-2009-2123948 (April 2010)
PA	West Penn Power	Electric	Smart Meter Surcharge	AMI	Docket No. M-2009-2123951 (June 2011)
RI	Narragansett Electric (electric operations)	Electric	Electric Infrastructure, Safety, and Reliability Plan Factor	Replacements and load growth	Docket No. 4218 (December 2011)
RI	Narragansett Electric (gas operations)	Gas	Gas Infrastructure, Safety, and Reliability Plan Factor	Replacement investment	Docket No. 4219 (September 2011)
SC	South Carolina Electric & Gas	Electric	NA	Nuclear generation	Docket 2008-196-E (March 2009)
SD	Black Hills Power	Electric	Environmental Improvement Adjustment tariff	Environmental	Docket EL11-001
SD	Northern States Power- MN	Electric	Environmental Cost Recovery Tariff	Environmental	Docket EL07-026 (January 2009)

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
TX	All Electric Utilities	Electric	Distribution Cost Recovery Factor	Any distribution	Docket 39465
TX	AEP Texas Central	Electric	Advanced Metering System Surcharge	AMI	Docket No. 36928
TX	AEP Texas North	Electric	Advanced Metering System Surcharge	AMI	Docket No. 36928
TX	Atmos Energy Mid Tex	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity	Texas Utilities Code 104.301 and Gas Utilities Docket 9615
TX	Atmos Energy Pipelines	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity	Texas Utilities Code 104.301 and Gas Utilities Docket 9615
TX	Atmos Energy West Texas Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity	Texas Utilities Code 104.301 and Gas Utilities Docket 9608
TX	Centerpoint Energy Entex - Houston Division	Gas	Gas Reliability Infrastructure Program	Incremental investment in new and replacement pipe, pipeline integrity	Texas Utilities Code 104.301 and Gas Utilities Docket 10067
TX	Centerpoint Energy Houston Electric	Electric	Advanced Metering System Surcharge	AMI	Docket No. 35620 (August 2008)
TX	Oncor Electric Delivery	Electric	Advanced Metering System Surcharge	AMI	Docket No. 35718 (August 2008)
TX	Texas-New Mexico Power	Electric	Advanced Metering System Surcharge	AMI	Docket No. 38306 (July 2011)
UT	Questar Gas	Gas	Infrastructure Rate Adjustment Tracker	Replacement of aging high-pressure feeder lines	Docket 09-057-16 (June 2010)
VA	Appalachian Power	Electric	Environmental & Reliability Cost Recovery Surcharge	Environmental & reliability	Docket No. PUE-2007-00069 (December 2007)
VA	Appalachian Power	Electric	Environmental Rate Adjustment Clause	Environmental	Case No. PUE-2011-00035 (November 2011)
VA	Appalachian Power	Electric	Generation Rate Adjustment Clause	Dresden plant	Docket No. PUE-2011-00036 (January 2012)
VA	Atmos Energy	Gas	Infrastructure Reliability and Replacement Adjustment	Replacement of first generation plastic pipe and service lines and bare steel mains and services	Case No. PUE-2012-00049 (August 2012)
VA	Columbia Gas of Virginia	Gas	SAVE Rider	Replacement of bare steel and cast iron mains, some early plastic pipe, isolated bare steel services, and risers prone to failure	Case No. PUE-2011-00049 (November 2011)
VA	Virginia Electric Power	Electric	Rider R	Bear Garden Generating Station	Case No. PUE-2009-00017 (March 2010)
VA	Virginia Electric Power	Electric	Rider S	Virginia City Hybrid Energy Center	Case No. PUE-2007-00066 (March 2008)
VA	Virginia Electric Power	Electric	Rider W	Warren County Power Station	Case No. PUE-2011-00042 (February 2012)
VA	Virginia Electric Power	Electric	Rider B	Biomass conversions	Case No. PUE-2011-00073 (March 2012)
VA	Washington Gas Light	Gas	SAVE Rider	Replacement of bare and unprotected steel services and mains, mechanically coupled pipe, copper services, cast iron main, and plastic services	Case No. PUE-2010-00087 (April 2011)
VT	Central Vermont Public Service	Electric	New Initiatives Adder	AMI	Dockets 7586 and 7612
WA	All gas utilities may file	Gas	Special Pipe Replacement Program Cost Recovery Mechanism	Replacement of pipe that is at an elevated risk of failure	Docket UG-120715 (December 2012)
WV	Appalachian Power	Electric	Construction/765kW Surcharge	Generation, Environmental	Case No. 11-0274-E-GI (June 2011)
WV	Wheeling Power	Electric	Construction/765kW Surcharge	Generation, Environmental	Case No. 11-0274-E-GI (June 2011)
WY	Black Hills Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket No. 20002-84-ET-12 (November 2012)
WY	Cheyenne Light, Fuel, & Power	Electric	Cheyenne Prairie Generating Station rate rider tariff	Construction of Cheyenne Prairie Generating Station	Docket No. 20003-123-ET-12 (November 2012)

Table 2 (continued)
Recent Capex Tracker Precedents

Jurisdiction	Company Name	Services Included	Tracker Name	Eligible Investments	Case Reference
			Historic		
CA	San Diego Gas & Electric	Electric & Gas	Advanced Metering Infrastructure Balancing Account	AMI	Application 05-03-015 (March 2005)
CA	Southern California Edison	Electric	Advanced Metering Infrastructure Balancing Account	AMI	Docket No. 07-07-042 (July 2007)
CO	Public Service Company of Colorado	Electric	Air Quality Improvement Rider	Environmental	Docket 98A-511E
GA	Atlanta Gas Light	Gas	Pipeline Replacement Program Cost Recovery Rider	Replacement of cast iron and bare steel pipe	Docket 8516-U later updated in Docket No. 29950 as STRIDE tracker in 2009
IL	Commonwealth Edison	Electric	Rider Systems Modernization Projects, renamed Rider Advanced Metering Pilot	AMI	Case 07-0566, Case 09-0263
IL	Peoples Gas Light & Coke	Gas	Rider Incremental Cost Recovery	Replacement of cast iron and bare steel pipe	Docket No. 09-0167 (January 2010)
KY	Union Light, Heat and Power (Duke Energy Kentucky)	Gas	Advanced Main Replacement Rider	Replacement of cast iron and bare steel mains and services	Docket No. 2001-00092 (January 2002)
NJ	Atlantic City Electric	Electric	Infrastructure Investment Surcharge	Replacements	Docket No. EO09010049 and GO09010054 (April 2009)
NJ	New Jersey Natural Gas	Gas	Accelerated Infrastructure Projects	Replace bare steel mains, reinforce distribution system & transmission mains	Docket No. GO09010052 and GR07110889 (April 2009)
NJ	New Jersey Natural Gas	Gas	Accelerated Infrastructure Projects II	Replace bare steel mains, reinforce distribution system & transmission mains	Docket No. GR10100793 (March 2011)
NY	Corning Natural Gas	Gas	Delivery Rate Adjustment	Incremental additions	Docket No. 08-G-1137 (March 2009)
NY	NYSEG	Gas	Gas Cost Savings Incentive Mechanism	Infrastructure that reduces the cost of gas supply	Docket No. 01-G-1668 (November 2002)
OH	Cleveland Electric Illuminating	Electric	Delivery Service Improvement Rider	Distribution reliability	0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OH	Columbus Southern Power	Electric	IGCC Surcharge (Phase I only)	Early IGCC development	Case No. 05-376-EL-UNC (April 2006)
OH	Columbus Southern Power	Electric	IGCC Surcharge (Phase II) IGCC Recovery Factor (Phase III)	IGCC	Case No. 05-376-EL-UNC (June 2006)
OH	Columbus Southern Power	Electric	Generation Cost Recovery Rider	Environmental	Case No. 07-63-EL-UNC (October 2007)
OH	Columbus Southern Power	Electric	Environmental Investment Carrying Charges (applies only to standard offer service customers)	Environmental	Case 08-917-EL-SSO (October 2011)
OH	Ohio Edison	Electric	Delivery Service Improvement Rider	Distribution reliability	Case No. 08-0935-EL-SSO, 09-0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OH	Ohio Power	Electric	Environmental Investment Carrying Charges (applies only to standard offer service customers)	Environmental	Case 08-917-EL-SSO (October 2011)
OH	Ohio Power	Electric	Generation Cost Recovery Rider	Environmental	Case No. 07-63-EL-UNC (October 2007)
OH	Ohio Power	Electric	IGCC Surcharge (Phase I only)	Early IGCC development	Case No. 05-376-EL-UNC (April 2006)
OH	Ohio Power	Electric	IGCC Surcharge (Phase II) IGCC Recovery Factor (Phase III)	IGCC	Case No. 05-376-EL-UNC (June 2006)
OH	Toledo Edison	Electric	Delivery Service Improvement Rider	Distribution reliability	Case No. 08-0935-EL-SSO, 09-0021-EL-ATA, 09-0022-EL-AEM, and 09-0023-EL-AAM (March 2009)
OK	Empire District Electric	Electric	Capital Recovery Rider	All incremental investment between rate cases	Cause No. PUD 201000033, Order 577904 (August 2010)
OK	Oklahoma Gas & Electric	Electric	OU Spirit Rider	OU Spirit Wind Farm	Cause No. 200900167, Order No. 571788 (October 2009)
OK	Oklahoma Gas & Electric	Electric	Smart Power Rider	Norman, Oklahoma pilot smart grid program	Cause No. 200800398
OK	Public Service Company of Oklahoma	Electric	Capital Investment Rider (CIR)	All incremental investment between rate cases	Cause No. 200900181 (August 2009)
OR	Northwest Natural Gas	Gas	NA	AMI	Docket UM 1413, Order 09-105 (March 2009)
OR	Northwest Natural Gas	Gas	Bare steel replacement program	Replacement of bare steel	Docket No. UM 1030, Order No. 01-843 (September 2001)
OR	Portland General Electric	Electric	NA	AMI	Docket UE 189, Order No. 08-245 (May 2008)
PA	PPL Electric Utilities	Electric	Energy Development Rider	Renewable interconnections	Docket No. M-00031715 F0003 (August 2006); Previously R-00973954 (May 14, 1998)
RI	Narragansett Electric (gas operations)	Gas	Accelerated Capital Replacement Program	Replacement of high pressure bare steel services inside customer premises	Docket No. 3943 (January 2009)
WV	Appalachian Power	Electric	NA: tracker included in the Expanded Net Energy Cost Mechanism	Transmission line, Environmental	Case No. 05-1278-E-PC-PW-42T (July 2006)

Figure 3: Recent Capex Tracker Precedents by State: Water Utilities

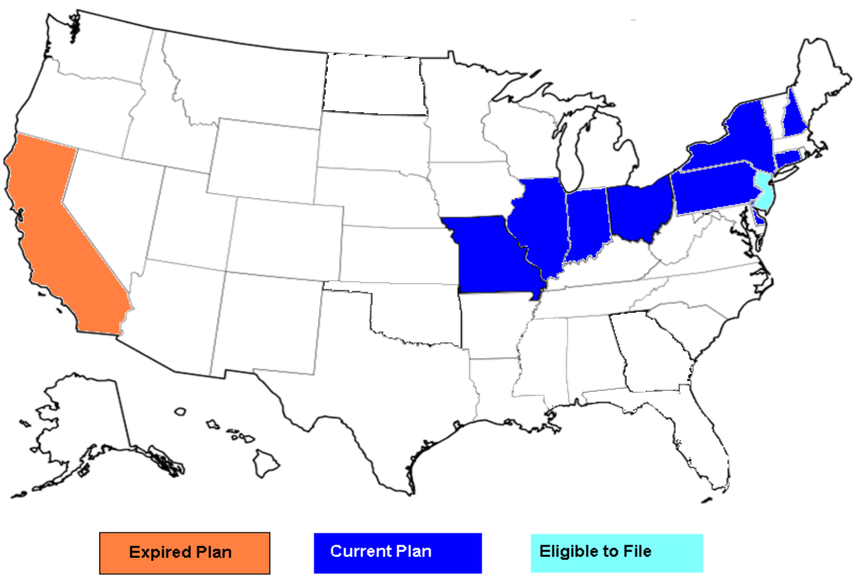


Figure 4: Recent Electric Precedents for CWIP In Rate Base

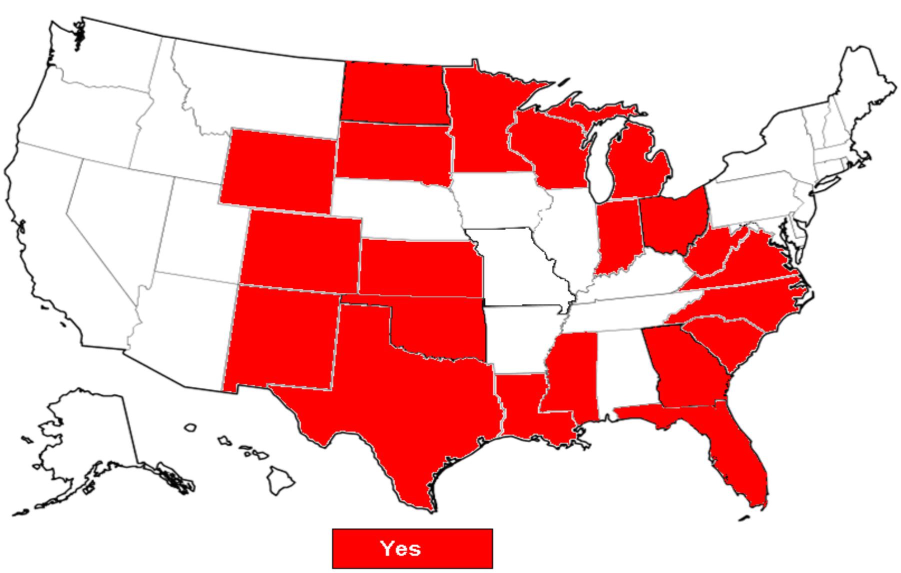


Table 3
CWIP in Rate Base: Recent Electric Retail Precedents

Jurisdiction	Company	Year Approved	Type of Project	Reference
Colorado	Public Service of Colorado	2006	Transmission, generation	Docket No. 06S-234EG
Colorado	Legislation	2007	Transmission	Senate Bill 07-100
Florida	Rulemaking	2007	Nuclear and IGCC generation	Docket 060508-EL
Florida	Florida Power & Light	2008	Nuclear generation	Docket 080650-EL
Florida	Progress Energy Florida	2008	Nuclear generation	Docket 080148-EI
Georgia	Georgia Power	2009	Nuclear generation	Docket 27800
Indiana	General Policy		Environmental	
Indiana	Duke Energy Indiana	2007	IGCC generation	Docket No. 43114
Kansas	Legislation	2008	Nuclear generation	Senate Bill 586
Louisiana	Rulemaking	2007	Nuclear generation	Docket R-29712
Louisiana	Cleco Power	2006	Generation	Docket U-28765
Michigan	Legislation	2008	Significant capital projects	House Bill 5524
Minnesota	Northern States Power- MN	2004	Environmental	Docket No. M-02-633
Minnesota	Minnesota Power	2007	Transmission	Docket M-07-965
Mississippi	Mississippi Power	2001	All projects within 1 year of completion	Docket No. 01-UN-0548
New Mexico	Legislation	2009	All	Senate Bill 477
North Carolina	Duke Energy Carolinas	2009	Generation	Docket No. E-7, Sub 909
North Carolina	Legislation	2007	Generation	Senate Bill 3
North Dakota	Legislation	2007	Transmission, federally mandated environmental	Senate Bill 2031 & House Bill 1221
Ohio	Legislation	2008	New Generation, Environmental	SB 221
Oklahoma	Legislation	2005	Environmental, transmission	House Bill 1910
South Carolina	South Carolina Electric & Gas	2003	Generation	Docket No. 2002-223-E
South Carolina	South Carolina Electric & Gas	2009	Nuclear generation	Docket 2009-211-E
South Dakota	Legislation	2006/2007	Transmission, environmental	
Texas	Rulemaking	2005	All Transmission within ERCOT (conditional)	Project 28884
Virginia	Legislation	2007	Reliability-related, nuclear, renewables, new generation using Virginia coal	Senate Bill 1416
Virginia	Virginia Electric Power	2008	New generation using Virginia coal	PUE-2007-00066
West Virginia	Appalachian Power	2006	Transmission, environmental, IGCC generation	Case No. 05-1278-E-PC-PW-42T
West Virginia	Monongahela Power	2007	Environmental	Case No. 05-0750-E-PC
Wisconsin	Wisconsin Public Service	2000	Nuclear generation, transmission	Docket 6690-UR-112
Wisconsin	Wisconsin Public Service	2005	Generation	Docket 6690-UR-117
Wisconsin	Wisconsin Power & Light	2012	All Commission approved projects	Docket 6680-UR-118
Wisconsin	General Policy		Diverse operations	
Wyoming	Black Hills Power	2012	Generation	Docket 20002-84-ET-12
Wyoming	Cheyenne Light, Fuel, & Power	2012	Generation	Docket 20003-123-ET-12

III. Revenue Decoupling

We use the term revenue decoupling to describe a diverse set of rate treatments designed to facilitate recovery of allowed revenue. The link between a utility's revenue and its sales is thereby weakened. This reduces the utility's disincentive to promote energy efficiency and can alleviate the financial stress caused by DSM programs and declining average use. DSM programs to encourage energy efficiency and discourage load peakedness can yield large cost savings for customers. Three approaches to decoupling are well established: decoupling true up plans, lost revenue adjustment mechanisms ("LRAMs"), and fixed variable pricing.

A. Decoupling True Up Plans

Decoupling true up plans adjust rates periodically to ensure that a utility's actual revenue tracks the revenue allowed by regulators. Most decoupling true up plans have two basic components: a revenue decoupling mechanism ("RDM") and an allowed revenue adjustment mechanism ("RAM"). The RDM tracks variances between actual and allowed revenue and makes periodic true ups. To the extent that recovery of allowed revenue is achieved, utilities can use rate designs more aggressively to promote DSM goals.

Decoupling true ups may be made annually or more frequently. More frequent adjustments cause actual and allowed revenue each year to correlate better so that rates fluctuate less from year to year. The size of the true up that is permitted in a given year is sometimes capped. A "soft" cap permits utilities to defer for later recovery any account balances that cannot be recovered immediately.

RDMs vary in the scope of utility services to which they apply. Quite commonly, only revenues from residential and commercial business customers are decoupled. These customers account for a high share of distribution base rate revenue and are usually the primary focus of DSM programs. RDMs also vary in terms of the service classes for which revenues are pooled for true up purposes. In some plans all service classes are placed in the same "basket". Other plans have multiple baskets. These insulate customers of services in each basket from changes in demands for services in other baskets.

Some RDMs are "partial" in the sense that they exclude from decoupling the revenue impact of certain kinds of demand fluctuations. For example, true ups are sometimes allowed only for the difference between weather normalized revenue and allowed revenue. An RDM that instead accounts for *all* sources of demand variance is called a "full" decoupling mechanism. Full decoupling provides more encouragement for rate design experimentation.

The RAM component of a decoupling true up plan escalates allowed revenue between rate cases. Virtually all decoupling true up plans have some kind of RAM because if allowed revenue is static the utility will experience financial attrition as its costs rise. Utilities that do not have RAMs in their decoupling true up plans often file annual rate cases.

Some RAMs are "broad-based" in the sense that they provide enough revenue growth to compensate the utility for several kinds of cost pressures. Broad-based RAMs are essentially the same thing as the revenue cap escalators that we discuss below in the section on multiyear rate plans. When RAMs are not broad-based, utilities usually retain the right to file rate cases during the decoupling plan and frequently do file. The revenue per customer ("RPC") freeze is a popular approach to RAM design. Allowed revenue grows at the same gradual pace as customer growth. An RPC freeze is not a broad-based RAM and will enhance expected revenue growth only when average use is expected to decline.

True up plans are the most popular approach to revenue decoupling in the United States. States that have tried gas and electric decoupling true up plans are indicated on the maps below in Figures 5a and 5b, respectively. Decoupling true up plan precedents in the United States and Canada are detailed in Table 4. It can be seen that there are more plans for gas utilities than for electric utilities. This reflects the fact that gas distributors have been much more likely to experience declining average use. Decoupling true up plans are nonetheless operative for a number of electric utilities in states with large DSM programs. Note also that RAMs for electric utilities are frequently broad-based, whereas most RAMs for gas distributors are revenue per customer freezes.

Figure 5a: Electric Decoupling True up Plans by State

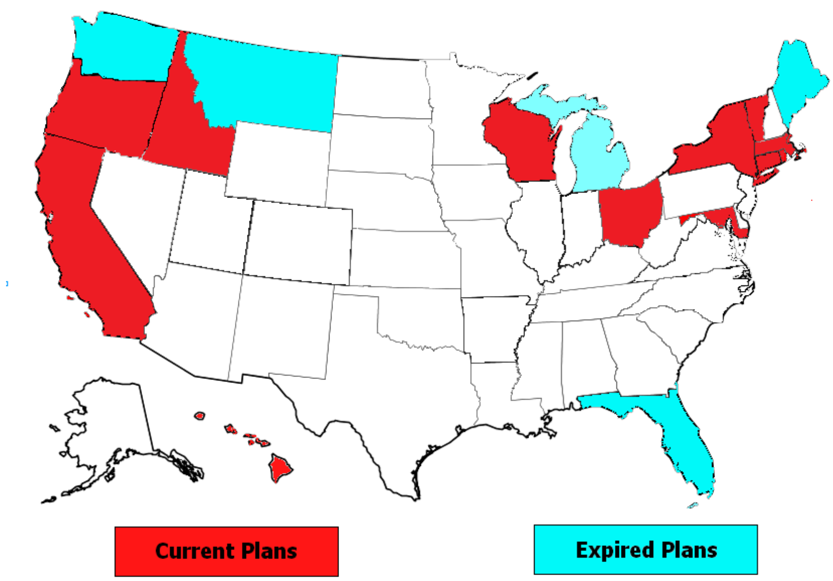


Figure 5b: Gas Decoupling True up Plans by State

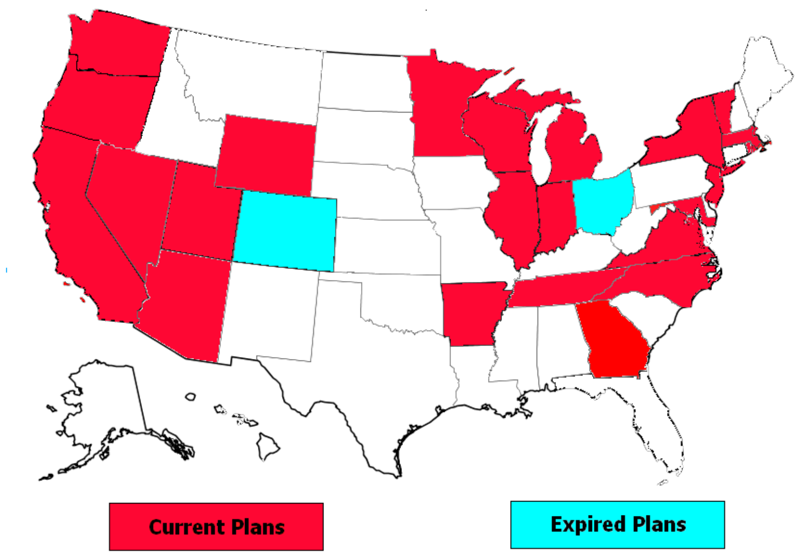


Table 4
Decoupling True Up Plan Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
			Current		
Canada					
AB	Altagas Utilities	Gas	2013-2017	RPC Index	Decision 2012-237
AB	ATCO Gas	Gas	2013-2017	RPC Index	Decision 2012-237
BC	BC Hydro	Electric	2012-2014	Stairstep	Order G-77-12A
BC	FortisBC	Electric	2012-2013	Stairstep	Order G 110-12
BC	Terasen Gas	Gas	2012-2013	Stairstep	Order G-44-12
BC	Pacific Northern Gas	Gas	2003-open	RPC Freeze	N/A
ON	Union Gas	Gas	2008-2012, extended through 2013	RPC Index through 2012, RPC Freeze for 2013	Docket EB-2007-0606
United States					
AR	CenterPoint Energy	Gas	2008-2015	No RAM but broad-based capex tracker	Dockets 06-161-U, 11-088-U
AR	Arkansas Oklahoma Gas	Gas	2007-2013	No RAM	Dockets 07-026-U, 07-077-TF
AR	Arkansas Western	Gas	2007-2013	No RAM	Docket 07-078-TF
AZ	Southwest Gas	Gas	2012-open	RPC Freeze	Docket No. G-01551A-10-0458
CA	California Pacific Electric	Electric	2013-2015	Indexing	Decision 12-11-030
CA	Pacific Gas & Electric	Gas & Electric	2011-2013	Stairstep	Decision 11-05-018
CA	Southwest Gas	Gas	2009-2013	Stairstep	Decision 08-11-048
CA	Southern California Edison	Electric	2012-2014	Hybrid	Decision 12-11-051
CA	Southern California Gas	Gas	2008-2011	Stairstep	Decision 08-07-046
CA	San Diego Gas & Electric	Gas & Electric	2008-2011	Stairstep	Decision 08-07-046
CT	United Illuminating	Electric	2009-open	Stairstep until 2011/No RAM for 2011 onwards	Docket No. 08-07-04
DC	Potomac Electric Power	Electric	2010-open	RPC Freeze	Order 15556
GA	Atmos Energy	Gas	2012-open	No RAM but FRP type mechanism also in effect	Docket No. 34734
HI	Hawaiian Electric Company	Electric	2011-open	Hybrid	0083
HI	Hawaiian Electric Light Company	Electric	2012-open	Hybrid	Docket No. 2008-0274, 2009-
HI	Maui Electric	Electric	2012-open	Hybrid	Dockets 2008-0274, 2009-0163
ID	Idaho Power	Electric	2012-open	RPC Freeze	Case No. IPC-E-11-19
IL	North Shore Gas	Gas	2012-open	No RAM	Case 11-0280
IL	Peoples Gas Light & Coke	Gas	2012-open	No RAM	Case 11-0281
IN	Indiana Gas	Gas	2011-2015	RPC Freeze	Cause No. 44019
IN	Vectren Southern Indiana	Gas	2011-2015	RPC Freeze	Cause No. 44019
IN	Citizens Gas	Gas	2007-open	RPC Freeze	Cause No. 42767
MA	Fitchburg Gas & Electric	Gas	2011-open	RPC Freeze	DPU 11-02
MA	Fitchburg Gas & Electric	Electric	2011-open	No RAM	DPU 11-01
MA	New England Gas	Gas	2011-open	RPC Freeze	DPU-10-114
MA	Western Massachusetts Electric	Electric	2011-open	No RAM	DPU 10-70
MA	Massachusetts Electric	Electric	2010-open	No RAM but broad-based capex tracker	DPU 09-39
MA	Bay State Gas	Gas	2009-open	RPC Freeze	DPU 09-30
MA	Boston-Essex Gas	Gas	2010-open	RPC Freeze	DPU 10-55
MA	Colonial Gas	Gas	2010-open	RPC Freeze	DPU 10-55
MD	Baltimore Gas & Electric	Electric	2008-open	RPC Freeze	Letter Orders ML 108069, 108061
MD	Delmarva Power & Light	Electric	2007-open	RPC Freeze	Order No. 81518
MD	Potomac Electric Power	Electric	2007-open	RPC Freeze	Order No. 81517
MD	Chesapeake Utilities	Gas	2006-open	RPC Freeze	Order No. 81054
MD	Washington Gas Light	Gas	2005-open	RPC Freeze	Order No. 80130
MD	Baltimore Gas & Electric	Gas	1998-open	RPC Freeze	Case No. 8780
MI	Michigan Consolidated Gas	Gas	2013-open	No RAM	Case No. U-16999
MI	Michigan Gas Utilities	Gas	2010-open	RPC Freeze	Case No. U-15990
MN	Minnesota Energy Resources	Gas	2012-2015	RPC Freeze	GR-10-977
MN	CenterPoint Energy	Gas	2010-2013	RPC Freeze	GR-08-1075
NC	Public Service Co of NC	Gas	2008-open	RPC Freeze	Docket No. G-5, Sub 495
NC	Piedmont Natural Gas	Gas	2008-open	RPC Freeze	Docket No. G-9, Sub 550
NJ	New Jersey Natural Gas	Gas	2010-2013	RPC Freeze	Docket GR05121020
NJ	South Jersey Gas	Gas	2010-2013	RPC Freeze	Docket GR05121019
NV	Southwest Gas	Gas	2009-open	RPC Freeze	D-09-04003
NY	Orange & Rockland Utilities	Gas	2012-open	RPC Freeze	Case 08-G-1398
NY	Corning Natural Gas	Gas	2012-2015	RPC Stairstep	Case 11-G-0280
NY	Orange & Rockland Utilities	Electric	2012-2015	Stairstep	Case 11-E-0408
NY	Niagara Mohawk	Electric	2011-open	No RAM	Case 10-E-0050
NY	New York State Electric & Gas	Gas & Electric	2010-2013	RPC Stairstep for Gas, Stairstep for Electric	Case 09-E-0715
NY	Rochester Gas & Electric	Gas & Electric	2010-2013	RPC Stairstep for Gas, Stairstep for Electric	Case 09-E-0717

Table 4 (continued)
Decoupling True Up Plan Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
NY	Consolidated Edison	Gas	2010-2013	RPC Stairstep	Case 09-G-0795
NY	Consolidated Edison	Electric	2010-2013	Stairstep	Case 09-E-0428
NY	Central Hudson G&E	Gas & Electric	2010-2013	RPC Stairstep for Gas, Stairstep for Electric	Case 09-E-0588
NY	Keyspan Energy Delivery - Long Island	Gas	2010-open	RPC Stairstep through 2012, RPC Freeze After 2012	Case 06-G-1186
NY	Keyspan Energy Delivery - New York	Gas	2010-open	RPC Stairstep through 2012, RPC Freeze After 2012	Case 06-G-1185
NY	Niagara Mohawk	Gas	2009-open	RPC Freeze	Case 08-G-0609
NY	National Fuel Gas	Gas	2008-open	RPC Freeze	Case 07-G-0141
OH	AEP Ohio	Electric	2012-2015	RPC Freeze	Case 11-351-EL-AIR
OH	Duke Energy Ohio	Electric	2012-2014	RPC Freeze	Case 11-5905-EL-RDR
OR	Northwest Natural Gas	Gas	2012-open	RPC Freeze	Order No. 12-408
OR	Portland General Electric	Electric	2011-2013	RPC Freeze	Order No. 10-478
OR	Cascade Natural Gas	Gas	2007-2012	RPC Freeze	Order No. 06-191
RI	Narragansett Electric	Electric	2012-open	No RAM but broad-based capex tracker	Docket 4206
RI	Narragansett Electric	Gas	2012-open	RPC Freeze	Docket 4206
TN	Chattanooga Gas	Gas	2010-2013	RPC Freeze	Docket 09-0183
UT	Questar Gas	Gas	2010-open	RPC Freeze	Docket No. 09-057-16
VA	Washington Gas Light	Gas	2010-2013	RPC Freeze	Case No. PUE-2009-00064
VA	Columbia Gas of Virginia	Gas	2013-2015	RPC Freeze	Case No. PUE-2012-00013
WA	Avista	Gas	2013-2014	Stairstep	Docket UG-120437
WI	Wisconsin Public Service	Gas & Electric	2013-open	No RAM	Docket 6690-UR-121
WY	Questar Gas	Gas	2012-open	RPC Freeze	Docket 30010-113-GR-11
WY	SourceGas Distribution	Gas	2011-open	RPC Freeze	Docket 30022-148-GR-10
			Historic		
Canada					
BC	BC Hydro	Electric	2011	No RAM	Order G-180-10
BC	BC Hydro	Electric	2009-2010	Stairstep	Order G-16-09
BC	Terasen Gas	Gas	2010-2011	Stairstep	Order G-141-09
BC	Terasen Gas	Gas	2008-2009	Hybrid	Order G-33-07
BC	Terasen Gas	Gas	2004-2007	Hybrid	Order G-51-03
BC	BC Gas	Gas	2000-2001	Hybrid	Order G-48-00
BC	BC Gas	Gas	1998-2000	Hybrid	Order G-85-97
ON	Enbridge Gas Distribution	Gas	2008-2012	RPC Index	Docket EB-2007-0615
United States					
CA	Pacific Gas & Electric	Gas & Electric	2007-2010	Stairstep	Decision 07-03-044
CA	Pacific Gas & Electric	Gas & Electric	2004-2006	Indexing	Decision 04-05-055
CA	Pacific Gas & Electric	Gas & Electric	1993-1995	Hybrid	Decision 92-12-057
CA	Pacific Gas & Electric	Electric	1990-1992	Hybrid	Decision 89-12-057
CA	Pacific Gas & Electric	Electric	1986-1989	Hybrid	Decision 85-12-076
CA	Pacific Gas & Electric	Electric	1984-1985	Hybrid	Decision 83-12-068
CA	Pacific Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93887
CA	Pacific Gas & Electric	Gas	1978-1981	No RAM	Decisions 89316, 91107
CA	PacifiCorp	Electric	1984-1985	Stairstep	Decision 89-09-034
CA	San Diego Gas & Electric	Gas & Electric	2005-2007	Indexing	Decision 05-03-025
CA	San Diego Gas & Electric	Gas & Electric	1994-1999	Hybrid	Decision 94-08-023
CA	San Diego Gas & Electric	Electric	1989-1993	Hybrid	Decision 89-11-068
CA	San Diego Gas & Electric	Gas & Electric	1986-1988	Hybrid	Decision 85-12-108
CA	San Diego Gas & Electric	Gas & Electric	1982-1983	Hybrid	Decision 93892
CA	Southern California Edison	Electric	2009-2011	Stairstep	Decision 09-03-025
CA	Southern California Edison	Electric	2006-2008	Hybrid	Decision 06-05-016
CA	Southern California Edison	Electric	2004-2006	Hybrid	Decision 04-07-022
CA	Southern California Edison	Electric	2001-2003	Indexing	Decision 02-04-055
CA	Southern California Edison	Electric	1986-1991	Hybrid	Decision 85-12-076
CA	Southern California Edison	Electric	1983-1984	Hybrid	Decision 82-12-055
CA	Southern California Gas	Gas	2005-2007	Indexing	Decision 05-03-025
CA	Southern California Gas	Gas	1998-2002	Indexing	Decision 97-07-054
CA	Southern California Gas	Gas	1986-1989	Hybrid	Decision 85-12-076
CA	Southern California Gas	Gas	1990-1993	Hybrid	Decision 90-01-016
CA	Southern California Gas	Gas	1981-1982	Stairstep	Decision 92497
CA	Southern California Gas	Gas	1979-1980	Stairstep	Decision 89710

Table 4 (continued)
Decoupling True Up Plan Precedents

Jurisdiction	Company Name	Services	Plan Years	Revenue Adjustment Mechanism	Case Reference
CO	Public Service Company of Colorado	Gas	2008-2011	RPC Freeze	Decision C07-0568
FL	Florida Power Corporation	Electric	1995-1997	RPC Freeze	Docket 930444
ID	Idaho Power	Electric	2007-2009	RPC Freeze	Case No. IPC-E-04-15
ID	Idaho Power	Electric	2010-2012	RPC Freeze	Case No. IPC-E-09-28
IL	North Shore Gas	Gas	2008-2012	RPC Freeze	Case 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-2012	RPC Freeze	Case 07-0242
IN	Vectren Energy	Gas	2007-2011	RPC Freeze	Cause No. 43046
IN	Vectren Southern Indiana	Gas	2007-2011	RPC Freeze	Cause No. 43046
IN	Citizens Gas	Gas	2007-2011	RPC Freeze	Cause No. 42767
ME	Central Maine Power	Electric	1991-1993	RPC Freeze	Docket No. 90-085
MI	Consumers Energy	Electric	2009-2011	RPC Freeze	Case No. U-15645
MI	Consumers Energy	Gas	2010-2012	RPC Freeze	Case No. U-15986
MI	Detroit Edison	Electric	2010-2011	RPC Freeze	Case No. U-15768
MI	Upper Peninsula Power	Electric	2010-2011	RPC Freeze	Case No. U-15988
MI	Michigan Consolidated Gas	Gas	2010-2012	RPC Freeze	Case No. U-15985
MT	Montana Power Company	Electric	1994-1998	RPC Freeze	Docket No. 93.6.24
NC	Piedmont Natural Gas	Gas	2005-2008	RPC Freeze	Docket G-44 Sub 15
NJ	New Jersey Gas Natural	Gas	2007-2010	RPC Freeze	Docket GR05121020
NJ	South Jersey Gas	Gas	2007-2010	RPC Freeze	Docket GR05121019
NY	Central Hudson G&E	Gas	2009-open	RPC Freeze	Case 08-E-0888
NY	Central Hudson G&E	Electric	2009-open	No RAM	Case 08-E-0887
NY	Consolidated Edison	Electric	2008-open	No RAM	Case 07-E-0523
NY	Consolidated Edison	Gas	2007-2010	Stairstep	Case 06-G-1332
NY	Consolidated Edison	Electric	1992-1995	Stairstep	Opinion No. 92-8
NY	Long Island Lighting Company	Electric	1992-1994	Stairstep	Opinion No. 92-8
NY	New York State Electric & Gas	Electric	1993-1995	Stairstep	Opinion No. 93-22
NY	Niagara Mohawk	Electric	1990-1992	Stairstep	Case 94-E-0098
NY	Orange & Rockland Utilities	Gas	2009-2012	RPC Stairstep	Case 08-G-1398
NY	Orange & Rockland Utilities	Electric	2011-2012	No RAM	Case 10-E-0362
NY	Orange & Rockland Utilities	Electric	2008-2011	Stairstep	Case 07-E-0949
NY	Orange & Rockland Utilities	Electric	1991-1993	Stairstep	Case 89-E-175
NY	Rochester Gas & Electric	Electric	1993-1996	Stairstep	Opinion No. 93-19
OH	Vectren Energy	Gas	2007-2009	RPC Freeze	Case 05-1444-GA-UNC
OR	Northwest Natural Gas	Gas	2009-2012	RPC Freeze	Order No. 07-426
OR	Northwest Natural Gas	Gas	2005-2009	RPC Freeze	Order No. 05-934
OR	Northwest Natural Gas	Gas	2002-2005	RPC Freeze	Order No. 02-634
OR	PacifiCorp	Electric	1998-2001	Indexing	Order No. 98-191
OR	Portland General Electric	Electric	2009-2010	RPC Freeze	Order No. 09-020
OR	Portland General Electric	Electric	1995-1996	Stairstep	Order No. 95-0322
UT	Questar Gas	Gas	2006-2010	RPC Freeze	Docket No. 05-057-T01
VA	Virginia Natural Gas	Gas	2009-2012	RPC Freeze	Case No. PUE-2008-00060
WA	Avista	Gas	2009-2012	RPC Freeze	Docket UG-060518
WA	Avista	Gas	2007-2009	RPC Freeze	Docket UG-060518
WA	Cascade Natural Gas	Gas	2005-2010	RPC Freeze	Docket UG-060256
WA	Puget Sound & Power	Electric	1991-1995	RPC Freeze	Docket UE-901184-P
WI	Wisconsin Public Service	Gas & Electric	2009-2012	RPC Freeze	D-6690-UR-119
WY	Questar Gas	Gas	2009-2012	RPC Freeze	Docket 30010-94-GR-08

B. Lost Revenue Adjustment Mechanisms

An LRAM explicitly compensates a utility for base rate revenues that are estimated to be lost due to its DSM programs, distributed generation ("DG"), or other specific causes. Compensation for lost margins is usually effected through a rate rider. Estimates of energy (and sometimes also peak load) savings are needed for LRAM calculations. The utility remains at risk for fluctuations in volumes and peak load due to weather, local economic activity, power market prices, and other volatile demand drivers. The utility is usually kept whole for the full revenue impact of its DSM (and possibly also DG) programs and not just for the incremental effort that causes average use to decline.[2] This is desirable because a program to promote DSM and DG increases the gap between cost and billing determinant growth and thereby increase potential attrition and the need for more frequent rate cases even if average use does not decline. Precedents for LRAMs are detailed in Table 5 and Figure 6 below.[3] It can be seen that, while LRAMs are less widely used than decoupling true up plans today, they have experienced a rebound in recent years and are more popular for electric than for gas utilities. For example, they are featured in Duke Energy's "Save a Watt" approach to DSM regulation and are also popular in the Intermountain West states. Some utilities have LRAMs and decoupling true up plans.

[2] For an example of an LRAM that covers DG as well as DSM programs, see Decision 73183 of the Arizona Corporation Commission in the 2012 rate case for Arizona Public Service. A multiyear rate plan was also approved in the decision.
[3] Some mechanisms similar to LRAMs are excluded from this survey.

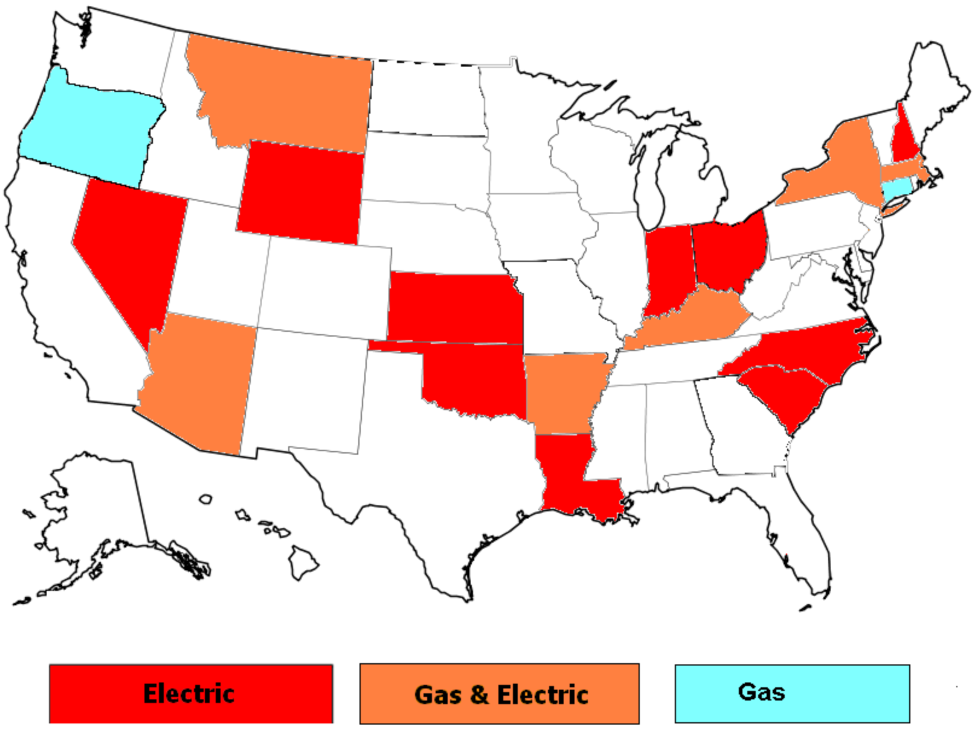
Table 5
Current LRAM Precedents

State	Company	Services	Approval Date	Case Reference
AR	Arkansas Oklahoma Gas	Gas	June 2011	Docket No. 07-077-TF, Order Number 30
AR	Centerpoint Energy Arkla	Gas	June 2011	Docket No. 07-081-TF, Order Number 31
AR	Entergy Arkansas	Electric	June 2011	Docket No. 07-085-TF, Order Number 40
AR	Oklahoma Gas & Electric	Electric	June 2011	Docket No. 07-075-TF, Order No. 26
AR	SourceGas Arkansas	Gas	June 2011	Docket No. 07-078-TF, Order No. 26
AR	Southwestern Electric Power	Electric	June 2011	Docket No. 07-082-TF, Order Nos. 35 and 36
AZ	Arizona Public Service	Electric	May 2012	Docket No. E-01345A-11-0224, Decision No. 73l83
AZ	UNS Gas	Gas	May 2012	Docket No. G-04204A-11-0158 Decision No. 73142
CT	Connecticut Natural Gas	Gas	August 1995	Docket No. 93-02-04
CT	Southern Connecticut Gas	Gas	August 1995	Docket No. 93-03-09
CT	Yankee Gas Service	Gas	January 2012	Docket No. 11-10-03
IN	Duke Energy Indiana (PSI)	Electric	February 2010	Cause No. 43374
IN	Indiana-Michigan Power	Electric	September 2010	Cause 43827
IN	Northern Indiana Public Service	Electric	May 2011	Cause 43618
IN	Southern Indiana Gas & Electric	Electric	August 2011 (large commercial and industrials), June 2012 (residential and small commercial)	Cause Nos. 43938 and 43405 DSMA 9 S1
KS	Kansas Gas & Electric	Electric	January 2011	Docket No. 10-WSEE-775-TAR
KS	Westar Energy	Electric	January 2011	Docket No. 10-WSEE-775-TAR
KY	Atmos Energy	Gas	September 2009	Case No. 2008-00499
KY	Columbia Gas of Kentucky	Gas	October 2009	Case No. 2009-00141
KY	Delta Natural Gas	Gas	July 2008	Docket No. 2008-00062
KY	Duke Energy Kentucky	Electric	December 1995 and February 2005	Case Nos. 95-321 and 2004-00389
KY	Duke Energy Kentucky	Gas	February 2005	Case No. 2004-00389
KY	Louisville Gas & Electric	Electric & Gas	November 1993	Case No. 93-150
KY	Kentucky Power	Electric	December 1995	Case No. 95-427
KY	Kentucky Utilities	Electric	May 2001	Case No. 2000-0459
LA	Entergy New Orleans	Electric	April 2009	New Orleans Resolution R-09-136
MA	All Electric distributors	Electric	July 2012	D.P.U. 12-01A
MA	Berkshire Gas	Gas	October 1992	D.P.U. 91-154
MA	NSTAR Electric	Electric	April 1992, June 1994, and June 2010	D.P.U. 90-335, D.P.U. 94-2/3-CC, and D.P.U. 10-06
MA	Commonwealth Gas d/b/a NSTAR Gas	Gas	November 1994	D.P.U. 94-128
MT	Northwestern Energy	Gas	February 2009	Docket No. D2008.5.44
MT	Northwestern Energy	Electric	December 2005	Docket No. D2004.6.90
MT	Montana-Dakota Utilities	Gas	October 2006	Docket No. D2005.10.156; Order No. 6697c

Table 5 (continued)
Current LRAM Precedents

State	Company	Services	Approval Date	Case Reference
NY	Central Hudson Gas & Electric	Electric	July 2006	Case No. 05-E-0934
NY	Consolidated Edison of New York	Electric	March 2005	Case No. 04-E-0572
NY	Consolidated Edison of New York	Gas	April 2002	Case No.00-G-1456
NY	Keyspan Long Island	Gas	December 2009	Case No. 06-G-1186; Currently effective for all customers not in RDM
NY	Keyspan New York	Gas	December 2009	Case No. 06-G-1185; Currently effective for all customers not in RDM
NC	Duke Energy Carolinas	Electric	February 2010	Docket No. E-7, Sub 831
NC	Progress Energy Carolinas (Carolina Power & Light)	Electric	November 2009	Docket No. E-2, Sub 931
NC	Virginia Electric Power	Electric	October 2011	Docket No. E-22, Sub 464
NH	Unitil Energy Services	Electric	June 2010	DE 09-137, Order No. 25,111
NV	Nevada Energy	Electric	May 2011	Docket 10-10024
NV	Sierra Pacific Power	Electric	May 2011	Docket 10-10025
OH	Duke Energy Ohio (Cincinnati Gas & Electric)	Electric	July 2007	Docket No. 06-0091-EL-UNC
OH	First Energy Ohio (Cleveland Electric Illuminating, Toledo Edison, Ohio Edison)	Electric	March 2009	Docket No. 08-935-EL-SSO
OH	American Electric Power (Ohio Power, Columbus Southern Power)	Electric	May 2010	Docket No. 09-1089-EL-POR; Effective for classes not included in RDM
OH	Dayton Power & Light	Electric	June 2009	Docket No. 08-1094-EL-SSO
OK	Empire District Electric	Electric	November 2009	Cause No. 200900146 Order 571326
OK	Oklahoma Gas & Electric	Electric	July 2008	Cause No. 200800059 Order 556179
OK	Public Service of Oklahoma	Electric	January 2010	Cause No. PUD 200900196; Order 572836
ON	Union Gas	Gas	January 2008	EB-2007-0606
ON	Enbridge Gas Distribution	Gas	February 2008	EB-2007-0615
ON	Toronto Hydro-Electric	Electric	September 2007	EB-2007-0096
OR	Portland General Electric	Electric	September 2001	Order No. 01-836; UE 79 (Approved 2001 LRAM) Currently non-residential customers only
OR	Cascade Natural Gas	Gas	April 2006	Order No. 06-191; UG 167 excludes classes under RDM
OR	Avista Utilities	Gas	December 1993	Order 93-1881
SC	Progress Energy Carolinas	Electric	June 2009	Docket No. 2008-251-E Order 2009-373
SC	Duke Energy Carolinas	Electric	January 2010	Docket No. 2009-226-E Order No. 2010-79
SC	South Carolina Electric & Gas	Electric	July 2010	Docket No. 2009-261-E, Order No. 2010-472
WY	Cheyenne Light, Fuel, and Power	Electric & Gas	September 2011	Docket Nos. 20003-108-EA-10 and 30005-140-GA-10
WY	Montana-Dakota Utilities	Electric	January 2007	Docket No. 20004-65-ET-06

Figure 6: Current LRAMs by State



C. Fixed Variable Pricing

Fixed variable pricing is an approach to the design of base rates that uses fixed charges (charges that do not vary with the sales volume or peak demand) to recover a high percentage of fixed costs. A *straight* fixed variable ("SFV") rate design recovers *all* fixed costs through fixed charges. A rate design that recovers a substantial but smaller share of fixed costs through fixed charges is sometimes called *modified* fixed variable pricing. Most fixed variable rate designs implemented to date have involved the same fixed charge for all customers in a service class. However, "sliding scale" rate designs have been developed which assign lower fixed charges to customers who are likely to have lower volumes.

The lion's share of base rate revenue from residential and commercial customers is typically raised using customer charges under fixed variable pricing. Revenue thus tends to grow at the gradual pace of customer growth.

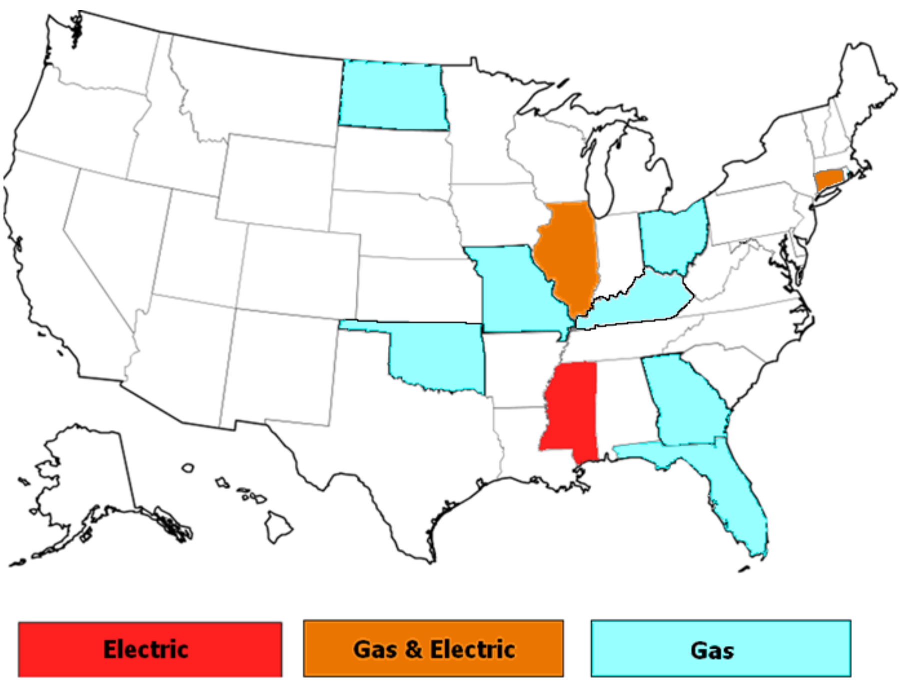
SFV pricing has been used on a large scale by interstate gas transmission companies since the early 1990s. Precedents for fixed variable pricing in retail ratemaking are listed below on Table 6 and Figure 7. It can be seen that fixed variable retail pricing has to date been more common for gas distributors than electric utilities. This again reflects the greater problem of declining average use that gas distributors have faced. Ohio is noteworthy for having recently switched from decoupling true up plans to fixed variable pricing for its gas distributors.

Table 6
Fixed Variable Retail Pricing Precedents

Jurisdiction	Company Name	Services	Years in Place	Case Reference
CT	Connecticut Light & Power	Electric	2007-open	Docket 07-07-01
CT	Yankee Gas System	Gas	2011-open	Docket 10-12-02
FL	Peoples Gas System	Gas	2009-open	Docket 080318-GU
GA	Altanta Gas Light	Gas	1998-open	Docket No. 8390-U
IL	Ameren CILCO	Gas	2008-2012	Case 07-0588
IL	Ameren CIPS	Gas	2008-2012	Case 07-0589
IL	Ameren IP	Gas	2008-2012	Case 07-0590
IL	Ameren Illinois	Gas	2012-open	Case 11-0282
IL	Commonwealth Edison	Electric	2011-open	Case 10-0467
IL	Nicor Gas	Gas	2009-open	Docket No. 08-0363
IL	North Shore Gas	Gas	2008-open	Case No. 07-0241
IL	Peoples Gas Light & Coke	Gas	2008-open	Case No. 07-0242
KY	Delta Natural Gas	Gas	2007-open	Case No. 2007-00089
KY	Duke Energy Kentucky	Gas	2010-open	Case No. 2009-00202
MO	AmerenUE	Gas	2007-open	Case No. GR-2007-0003
MO	Atmos Energy	Gas	2007-2010	Case GR-2006-0387
MO	Atmos Energy	Gas	2010-open	Case No. GR-2010-0192
MO	Empire District Gas	Gas	2010-open	Case GR-2009-0434
MO	Missouri Gas Energy	Gas	2007-open	Case GR-2006-0422
MO	Laclede Gas	Gas	2002-open	Case GR-2002-356
MS	Mississippi Power	Electric	Occurred over period of years	No specific case
ND	Xcel Energy	Gas	2005-open	Case PU-04-578
OH	Duke Energy Ohio (CG&E)	Gas	2008-open	Case 07-590-GA-ALT
OH	Dominion East Ohio	Gas	2008-2010	Case 07-830-GA-ALT
OH	Columbia Gas	Gas	2008-open	Case 08-0072-GA-AIR
OH	Vectren Energy Delivery of Ohio	Gas	2009-open	Case 07-1080-GA-AIR
OK	Oklahoma Natural Gas	Gas	2004-open	Cause Nos. PUD 200400610, PUD 201000048, PUD 200900110
OK	Centerpoint Energy	Gas	2010-open	Cause No. PUD 201000030

In addition to the precedents listed here, some other states have in recent years made sizable steps in the direction of fixed variable pricing by redesigning rates for small volume customers to raise customer charges and lower volumetric charges substantially. Investor-owned utilities in Canada are typically permitted to raise a much higher portion of their revenue through fixed charges than in the United States. Most fixed variable rate designs feature uniform fixed charges within service classes, but gas utilities in Florida, Georgia, and Oklahoma have fixed charges that vary in some fashion with long term consumption patterns.

Figure 7: Fixed Variable Pricing Precedents by State



IV. Forward Test Years

General rate cases involve "test years" in which revenue requirements and billing determinants are jointly considered in setting new rates. An historic test year ends before the rate case is filed. A fully-forecasted (a/k/a "forward") test year ("FTY") is a twelve month period that begins after the rate case is filed. An FTY typically begins about the time that the rate case is expected to end. Two-year forecasts are therefore required to span both the rate case year and the year that rates take effect.[4] In between FTYs and historic test years is the option of a "partially forecasted" test year in which some months of historic data on utility operations are combined with some months of forecasted data. Under this approach, actual data for all months usually become available during the course of the rate case.

Historic test years are chronically uncompensatory when cost grows materially faster than billing determinants. Annual rate cases can alleviate but not eliminate underearning. Where historic test years are used in rate cases there are thus added advantages to implementing other Altreg innovations discussed in this paper.

Forward test years can compensate utilities for a tendency of cost growth to exceed billing determinant growth.[5] If this tendency is chronic, however, it does not eliminate the problem of frequent rate cases. It is therefore not unusual for regulators to combine FTYs with other Altreg remedies, as is the case in California and New York.

Diverse approaches are used to forecast costs in FTY rate cases. Some companies rely on their budgeting process to make cost projections. Others normalized data for an historical reference period and adjust for known and measurable changes and then use indexing and other statistical methods to extend projections. Mixes of these two approaches are common.

Forward test years were adopted in many jurisdictions during the 1970s and 1980s when rapid price inflation and major plant additions coincided with slowing growth in average use. This approach to Altreg was therefore one of the earliest implemented. Several additional states have recently moved in the direction of FTYs. Many of these states are in the West, where comparatively rapid economic growth has required more rapid build out of utility infrastructure. FTYs were recently sanctioned legislatively in Pennsylvania.

Current state policies concerning test years are summarized below in Figure 8 and Table 7. The ranks of US jurisdictions that allow the use of alternatives to historic test years have swollen and now encompass well over half of the total. The "other" category in Figure 8 includes states where utilities can file FTYs but many do not (*e.g.* Illinois), states where FTYs may be approved on a case by case basis (*e.g.* New Mexico, Utah, and Wyoming), and states where partially forecasted test years are the norm (*e.g.* Ohio and New Jersey). Forward test years are the norm in Canada and several jurisdictions have permitted two forward test years.

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[4] A forward test year can be the rate case year, and thereby not require two-year forecasts, if rates are allowed to be changed as proposed on an interim basis shortly after the filing.

[5] The effect on credit metrics can be material. For evidence see "Forward Test Years for US Electric Utilities" by Mark Newton Lowry, David Hovde, Lullit Getachew, and Matt Makos, August 2010. Prepared for the Edison Electric Institute.

Figure 8: Test Year Policy by State

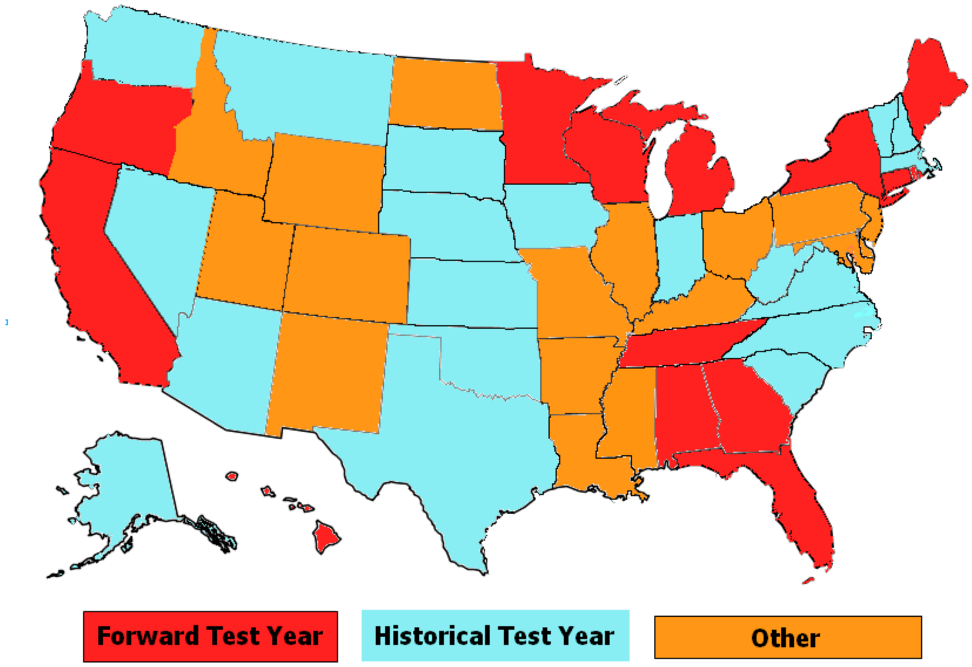


Table 7
Test Year Approaches of US Jurisdictions

Jurisdiction	Notes
Fully-Forecasted (15)	
Alabama	Utilities operate under forward-looking formula rate plans
California	
Connecticut	
FERC	Rate cases use forward test years but some formula rate plans use HTYs
Florida	
Georgia	
Hawaii	
Maine	
Michigan	
Minnesota	
New York	
Oregon	
Rhode Island	
Tennessee	
Wisconsin	
Partially-Forecasted (3)	
Arkansas	
Ohio	
New Jersey	
Transitional/Varying (14)	
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently
Delaware	Before restructuring FTY filings were common, but companies have used a mix of HTYs and partially-forecasted test years in recent filings
Idaho	
Illinois	Utilities use various test years including FTYs
Kentucky	Utilities use various test years including FTYs
Louisiana	Utilities use various test years including FTYs
Maryland	Utilities use various test years excluding FTYs
Mississippi	One electric utility operates under a forward-looking formula rate plan
Missouri	Utilities have the option to file partially-forecasted test years
New Mexico	A recently passed law allows for use of FTYs, but no rate increase based on FTY evidence has yet been approved
North Dakota	Utilities use various test years including FTYs
Pennsylvania	Partially-forecasted test years have been the norm. Law allowing fully-forecasted test years passed in 2012. First FTY case is pending.
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently used FTYs
Historic (20)	
Alaska	
Arizona	
Colorado	Utilities can file FTY evidence. No FTY rates have yet been approved but a recent case made extraordinary HTY adjustments.
Indiana	
Iowa	
Kansas	
Massachusetts	
Montana	
Nebraska	Nebraska has no electric IOUs. Gas companies are legally authorized to use FTYs but commonly use HTYs.
Nevada	
New Hampshire	
North Carolina	
Oklahoma	
South Carolina	
South Dakota	
Texas	
Vermont	
Virginia	
Washington	
West Virginia	

V. Multiyear Rate Plans

Multiyear rate plans ("MRPs") are designed to compensate a utility for changing business conditions without frequent, full true ups to its actual cost of service. Rate cases are held infrequently, most often at three to five year intervals. Any rate escalations that are made between rate cases are based in whole or in part on automatic attrition relief mechanisms ("ARMs"). The rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth. The "externalization" of ratemaking that these two features of MRPs achieve can strengthen utility performance incentives despite a reduction in regulatory cost. Benefits of better performance can be shared between the utility and its customers. Lower regulatory cost has special appeal in jurisdictions where numerous utilities must be regulated.

ARMs typically cap the growth in either rates (*e.g.* customer charges and cents per kWh) or allowed revenue. Rate caps are favored when and where utilities are encouraged to bolster system use since they strengthen incentives to promote use and facilitate marketing flexibility by reducing concerns about cross-subsidies. Revenue caps are usually combined with decoupling true ups, and are often favored where utilities must cope with declining average use and/or large-scale DSM programs.

Several approaches to the design of ARMs are well-established. These approaches include stairsteps, indexing, and hybrids. Stairsteps provide predetermined increases in rates (or revenue) which often reflect forecasts of cost growth. Indexing escalates rates (or revenue) automatically for inflation and sometimes also for growth in the number of customers served and/or industry productivity trends. Hybrid ARMs typically involve indexing of budgets for O&M expenses and stairsteps for capital cost budgets.

The indexing approach to ARM design is more common for distribution charges because distribution cost growth is relatively gradual and predictable. Hybrid and stairstep ARMs are more adaptable to the cost growth trajectories of VIEUs, which are more uneven due to occasional major plant additions. Some VIEUs operating under MRPs have separate ratemaking treatments for generation and distribution.

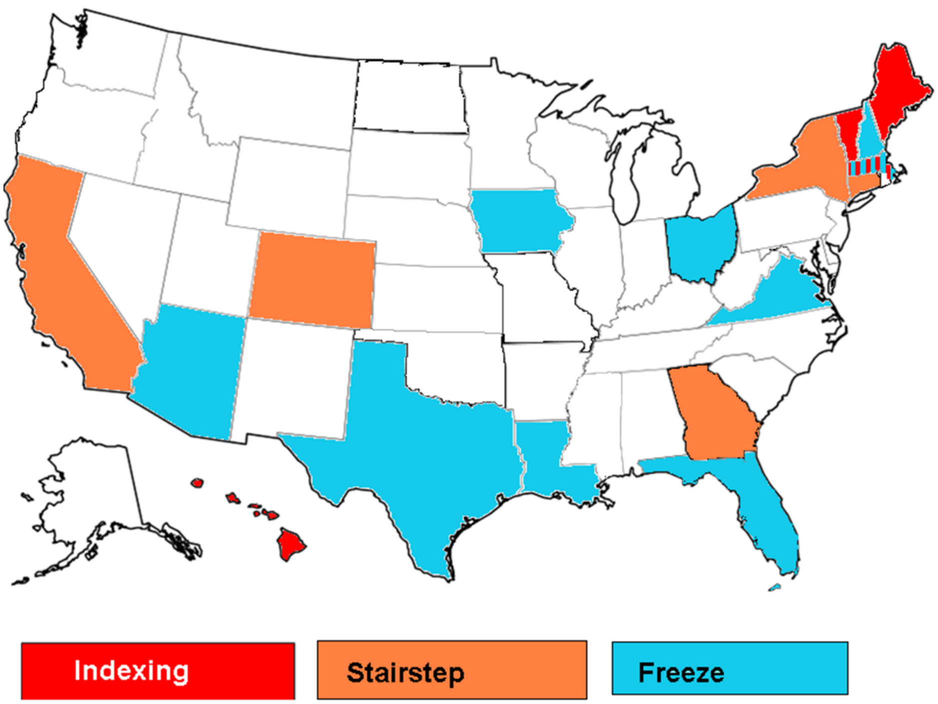
Supplemental rate adjustments are usually allowed for changes in business conditions that are especially difficult to address using ARMs. A tracker that recovers a large portion of a utility's capex cost can, for example, sometimes permit the company to operate under a multiyear freeze on rates for other non-energy costs. This is so because the value of the residual rate base is more likely to be static or decline. Trackers may also address *force majeure* events such as severe storms and changes in tax rates and other government policies that affect costs.

Some multiyear rate and revenue caps feature earnings sharing mechanisms ("ESMs") that automatically share earnings surpluses and/or deficits that result when the rate of return on equity ("ROE") deviates from its regulated target. Some feature "off-ramps" that permit plan suspension when earnings are unusually high or low. Plans often feature award and/or penalty mechanisms that are linked to the utility's service quality.

MRPs were first widely used in the railroad, telecommunications, and oil pipeline industries. A major attraction was the ability of price caps to afford utilities flexibility in serving markets with diverse competitive pressures from a consolidated set of assets. The use of MRPs in the regulation of gas and electric utilities has been chiefly motivated by other advantages such as stronger performance incentives and lower regulatory cost.

Current US and Canadian precedents for MRPs are indicated in Table 8 and Figures 9a and 9b.[6] In the US, multiyear rate plans are most common in California and the Northeast. MRPs with ARMs that escalate rate or revenue automatically are more common for energy distributors than for VIEUs. Canada is moving towards MRPs with index-based ARMs for pipe and wire utilities in all four populous provinces. MRPs with index-based ARMs are more the rule than the exception for pipe and wire utilities overseas. ARMs used in MRPs for VIEUs typically have a stairstep or hybrid form. Other VIEUs operate under a combination of a rate freeze and one or more trackers to compensate the utility for specific causes of potential attrition.

Figure 9a: Recent US Electric Multiyear Rate Cap Precedents by State



[6] The table considers only MRPs that weren't listed in Table 4 on decoupling true up precedents. Figures 9a and 9b cover all MRPs. Rate freezes without extensive supplemental funding from trackers are excluded from Table 8 and Figures 9a and 9b.

Table 8
Multiyear Price Cap Precedents[1,2]

Jurisdiction	Company Name	Plan Term	Services Covered	Rate Escalation Provisions	Case Reference
Current					
AZ	Arizona Public Service	2012-2016	Bundled power service	Rate freeze with an adjustment to account for purchase of SCE's share of Four Corners generating facility, additional capex and other cost trackers, LRAM	Decision No. 73183, May 2012
CA	PacifiCorp	2011-2013	Bundled power service	Price Cap Index: Rates escalated by Global Insight forecast of CPI, less 0.5% productivity factor; supplemental funding for major plant additions can be requested in annual filings.	Decision 10-09-010; September 2, 2010
CO	Public Service Company of Colorado	2012-2014	Bundled power service	Stairstep	Decision No. C12-0494
FL	Florida Power & Light	2013-2016	Bundled power service	Rate freeze with multiple capex and other cost trackers	Docket No. 120015-EI, December 2012
FL	Progress Energy Florida	2012-2016	Bundled power service	Rate Freeze with one step plus capex and other cost trackers	Docket No. 120022-EI
GA	Georgia Power	2011-2013	Bundled power service	Stairstep: Rate increases permitted for DSM and major generation plant additions	Docket 31958
IA	MidAmerican Energy	2001 - 2005, extended to 2013	Bundled power service	Rate Freeze with nuclear capex and other cost trackers	Dockets RPU-01-3 and RPU-2012-0001
LA	Cleco	2009-2014	Bundled power service	Rate freeze with capex tracker	Order No. U-30689
ME	Central Maine Power (III)	2009-2013	Power distribution	Price Cap Index: GDPPI - 1%, separate AMI tracker	Docket 2007-215
NH	Public Service Company of New Hampshire	2010-2015	Power distribution (generation regulated separately)	Stairstep: Rate increases allowed to account for distribution capital additions in 2010-2013	DE 09-035
NH	Unitil Energy Systems	2011-2016	Power distribution	Stairstep: Rate increases allowed to account for distribution capital additions in 2011-2013	DE 10-055
OH	AEP-OH	2012-2015	Power distribution	Rate Freeze supplemented by capex and other cost trackers	Case No. 11-346-EL-SSO, August 8, 2012
OH	First Energy Ohio	2011-2014, later extended to 2016	Power distribution	Rate Freeze with capex and other cost trackers	Case Nos. 11-388-EL-SSO, 12-1230-EL-SSO
VA	Virginia Electric Power	2010-2013	Bundled power service	Rate Freeze with capex and other cost trackers	Case No. PUE-2009-00019
VT	Green Mountain Power	2010-2013	Electric	Revenue cap index	Docket No. 7585
VT	Central Vermont Public Service	2011-2013	Electric	Revenue cap index	Docket No. 7627
VT	Vermont Gas Systems	2012-2015	Gas	Revenue cap hybrid	Docket No. 7803
Alberta	Enmax	2007-2013	Power distribution	Price Cap Index: Input Price Index -1.2%	Decision 2009-035
Alberta	Altagas Utilities	2013-2017	Gas	Revenue Per Customer Indexing: Input Price Index - 1.16%, separate capex trackers	Decision 2012-237
Alberta	ATCO Gas	2013-2017	Gas	Revenue Per Customer Indexing: Input Price Index - 1.16%, separate capex trackers	Decision 2012-237
Alberta	EPCOR, Fortis Alberta	2013-2017	Power distribution	Price Cap Index: Input Price Index - 1.16%, separate capex trackers	Decision 2012-237
Northwest Territories	Northland Utilities	2011-2013	Bundled power service	Stairstep	Decision 17-2011
Northwest Territories	Northland Utilities (Yellowknife)	2011-2013	Bundled power service	Stairstep	Decision 13-2011

Table 8 (continued)
Multiyear Price Cap Precedents[1,2]

Current

Jurisdiction	Company Name	Plan Term	Services Covered	Rate Escalation Provisions	Case Reference
Ontario	All Ontario distributors	2010-2013	Power distribution	Price Cap Index: GDP IPI for Final Domestic Demand - (0.92% to 1.32% depending on company's annual performance in benchmarking studies)	EB-2007-0673 (July 14, 2008, September 17, 2008, and January 28, 2009)
Prince Edward Island	Maritime Electric	2013-2016	Bundled power service	Stairstep: Bill defines rates for each year.	Bill 26 (2012) Electric Power (Energy Accord Continuation) Amendment Act

Historic

Jurisdiction	Company Name	Plan Term	Services Covered	Attrition Relief Mechanisms	Case Reference
CA	Sierra Pacific Power	2009-2011, extended to 2012	Bundled power service	Price Cap Index	Decision 09-10-041
CA	PacifiCorp	1994-1996, extended to 1999	Bundled power service	Price Cap Index	Decision 93-12-106; December 3, 1993
CA	PacifiCorp	2007-2009, extended to 2010	Bundled power service	Price Cap Index	Decisions 06-12-011 and 09-04-017
CA	San Diego Gas and Electric	1999-2002	Electric & Gas	Price Cap Index	Decision 99-05-030; May 13, 1999
CA	Southern California Edison	1997-2001	Electric	Price Cap Index	Decision 96-09-092; September 6, 1996
CT	United Illuminating	2006-2008	Power Distribution	Stairstep	Docket 05-06-04
FL	Florida Power & Light	2006-2009	Bundled power service	Rate Freeze with exception for new generating facilities after they are in service and multiple capex and other cost trackers	Docket 050045-EI
FL	Progress Energy Florida	2006-2009	Bundled power service	Rate freeze with 1 step to reflect generation brought in-service and multiple capex and other cost trackers	Docket No. 050078-EI
GA	Atlanta Gas Light	2005-2010	Gas distribution	Base rate freeze featuring a broad-based capex tracker	Docket No. 18638-U
MA	Bay State Gas	2006-2009	Gas distribution	Price Cap Index	Docket DTE 05-27
MA	Berkshire Gas	2002-2012	Gas distribution	No adjustment until September 2004, then Price Cap Index	Docket D.T.E. 01-56
MA	Boston Gas (I)	1997-2001	Gas distribution	Price Cap Index	Docket D.P.U. 96-50-C (Phase I) May 16, 1997
MA	Boston Gas (II)	2004-2010	Gas distribution	Price Cap Index	Docket DTE 03-40
MA	Blackstone Gas	November 1, 2004 - October 31, 2009	Gas distribution	Price Cap Index	Docket D.T.E. 04-79
MA	National Grid	2000-2010	Power distribution	Rate Freeze between 2000 and 2005, Price Cap Index: 2006-2010, inflation adjustment made based on index of regional power distribution charges.	Docket DTE 99-47 (November 29, 1999)
MA	Nstar	2006-2012	Power distribution	Price Cap Index	Docket D.T.E. 05-85
ME	Bangor Gas	2000-2009, extended to 2012	Gas Distribution	Price Cap Index	Docket 970795 (June 26, 1998)
ME	Bangor Hydro Electric (I)	1998-2000	Power distribution	Price Cap Index	Docket 97-116 (March 24, 1998)
ME	Bangor Hydro Electric (II)	2002-2007	Power Distribution	Stairstep	Docket No. 2001-410
ME	Central Maine Power (I)	1995-1999	Bundled power service	Price Cap Index	Docket 92-345 Phase II (January 10, 1995)
ME	Central Maine Power (II)	2001-2007	Power distribution	Price Cap Index	Docket 99-666 (November 16, 2000)

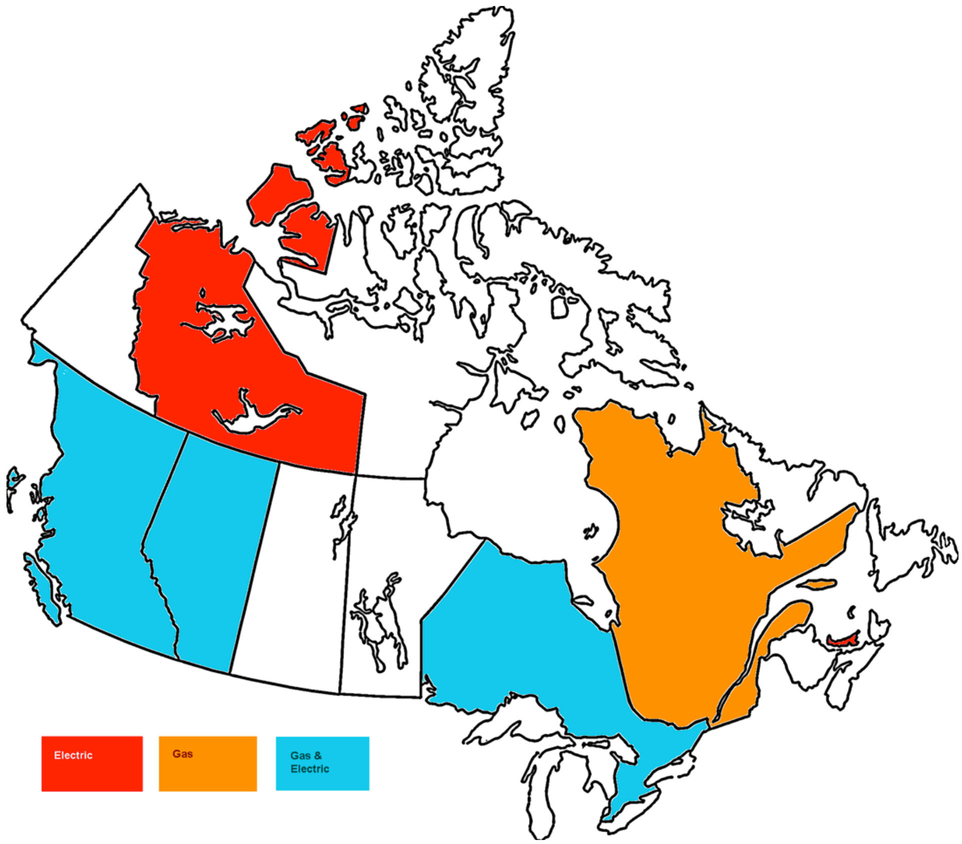
Table 8 (continued)
Multiyear Price Cap Precedents[1,2]

Historic

Jurisdiction	Company Name	Plan Term	Services Covered	Rate Escalation Provisions	Case Reference
NY	Brooklyn Union Gas	October 1, 1991 - September 30, 1994	Gas distribution	Stairstep	Case 90-G-0981, Opinion 91-21, October 9, 1991
NY	Brooklyn Union Gas	October 1, 1994 - September 30, 1997	Gas distribution	Stairstep	Case 93-G-0941, Opinion 94-22, October 18, 1994
NY	Central Hudson Gas & Electric	July 1, 2006 - June 30, 2009	Electric & Gas	Stairstep	Case 05-E-0934 & Case 05-G-0935; July 24, 2006
NY	Consolidated Edison	October 1, 1994 - September 30, 1997	Gas Distribution	Stairstep	Case 93-G-0996, Opinion 94-21, October 12, 1994
NY	Consolidated Edison	April 1, 2005 - March 31, 2008	Power distribution	Stairstep	Case 04-E-0572, March 24, 2005
NY	Long Island Lighting Company	December 1, 1993- November 30, 1996	Gas distribution	Stairstep	Case 93-G-0002, Opinion 93-23, December 23, 1993
NY	New York State Electric & Gas	December 1, 1993 - August 31, 1995	Gas	Stairstep	Case 92-G-1086, Opinion 93-22, November 9, 1993
NY	New York State Electric & Gas	August 1, 1995 - July 31, 1998, Years 2 and 3 not implemented due to restructuring	Electric	Stairstep	Case 94-M-0349, Opinion 95-27, September 27, 1995
NY	Niagara Mohawk	July 1, 1990 - December 31, 1992	Gas	Stairstep	Case 29327, Opinion 89-37, June 28, 1991
NY	Orange & Rockland Utilities	November 1, 2003- October 31, 2006	Gas	Stairstep	Case 02-G-1553, October 23, 2003
NY	Orange & Rockland Utilities	November 1, 2006 - October 31, 2009	Gas	Stairstep	Case 05-G-1494, October 20, 2006
NY	Rochester Gas & Electric	July 1, 1993 - June 30, 1996	Gas	Stairstep	Case 92-G-0741, Opinion No. 93-19; August 24, 1993
OH	Cincinnati Gas & Electric	2009-2011	Power generation	Stairstep	Case 08-920-EL-SSO
OH	Dayton Power & Light	2009-2012	Power Distribution	Rate freeze supplemented by capex and other cost trackers	Case No. 08-1094-EL-SSO (June 2009)
VT	Green Mountain Power	2007-2010	Electric	Stairstep	Docket No. 7176
VT	Vermont Gas Systems	2007-2012	Gas	Hybrid	Docket No. 7109
Alberta	Northwestern Utilities	1999-2002	Bundled power service	Stairstep	Decision U98060 (March 31, 1998)
Alberta	EPCOR	2002-2005, Terminated 12/31/2003	Power distribution	Price Cap Index	City of Edmonton Distribution Tariff Bylaw 12367 (August 18, 2000)
BC	Fortis BC	2006-2009, extended to 2011	Bundled power service	Revenue Cap Hybrid	Order G-58-06
Ontario	All Ontario distributors	2000-2003	Power distribution	Price Cap Index	RP-1999-0034
Ontario	All Ontario Distributors	2006-2009	Power Distribution	Price Cap Index	EB-2006-0089 (December 20, 2006)
Ontario	Union Gas	2001-2003	Gas distribution	Price Cap Index	RP-1999-0017 (July 21, 2001)

1 Rate freezes without extensive supplemental funding from capex trackers are excluded from this table.
2 MRPs with revenue decoupling and broad-based revenue cap escalators are detailed in Table 4.

Figure 9b: Recent Canadian Multiyear Rate Cap Precedents by Province



VI. Formula Rates

A cost of service formula rate plan ("FRP") is essentially a wide-scope cost tracker designed to help a utility's revenue track its pro forma cost of service. When revenue and cost are not balanced a utility's realized ROE deviates from the target set by regulators, and earnings surpluses or deficits occur. FRPs have earnings true up mechanisms that adjust rates so that earnings variances are substantially reduced or eliminated. Regulatory cost is reduced by limiting review of costs and revenues.

The earnings true up mechanism in an FRP calculates the revenue adjustment necessary to reduce or eliminate earnings variances. Some compare the earned ROE to the target (a/k/a benchmark) ROE and then calculate the rate adjustment needed to reduce the ROE variance. Another approach is to adjust rates for the difference between revenue and a pro forma cost of service that is calculated using a rate of return target. Both approaches often add interest on the variance to the revenue adjustment.

Earnings true up mechanisms in FRPs commonly move the ROE all, or almost all, of the way to its regulated target without sharing earnings variances. This is an important distinction between an FRP earnings true up mechanism and the earnings *sharing* mechanisms found in some multiyear rate plans. ESMs also frequently have sizable deadbands.

Expedited review of operating prudence does not always extend to major investment programs. In state-regulated FRPs for retail services, for instance, major investment programs are generally approved separately through such means as hearings on certificates of public convenience and necessity. The resultant cost is sometimes recovered through a separate tracker. Mechanisms are sometimes added to an FRP to encourage better operating performance in targeted areas. An example is a limit on the escalation of O&M expenses using an indexing formula.

Formula rates have been used at the FERC and its predecessor agency to regulate interstate services of gas and electric utilities since at least 1950. Use of FRPs was encouraged in the 1970s and early 1980s by rapid price inflation. Despite slower inflation in recent years, the FERC has made extensive use of formula rates for power transmission in an effort to simplify its daunting regulatory task and facilitate urgently needed investments.

Precedents for retail formula rates, which recover costs of generation and/or distribution, are listed in Table 9 and Figure 10[7]. It can be seen that FRPs for retail utility services are operative today in several Southeast and South Central states. Alabama was an early innovator, approving "Rate Stabilization and Equalization" plans for Alabama Power and Alabama Gas in the early 1980s.[8] Formula rates are, additionally, now used to regulate electric utilities in Mississippi, some gas and electric utilities in Louisiana, and some gas utilities in Oklahoma, Texas, and South Carolina. Utilities in other states have cost trackers that act like formula rates to recover their transmission costs from retail customers Most of the recent approvals of formula rates have been for gas distribution, as this is one means of avoiding the frequent rate cases that declining average use can trigger. However, formula rates were recently authorized for electric utilities in Illinois and two are now operating under FRPs there.

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7 Some plans labeled as formula rates do not qualify for inclusion in this table and figure based on our definition.
8 For further discussion of the Alabama FRP experience see Edison Electric Institute, *Case Study of Alabama Rate Stabilization and Equalization Mechanism*, June 2011.

Table 9
Retail Formula Rate Plan Precedents[1]

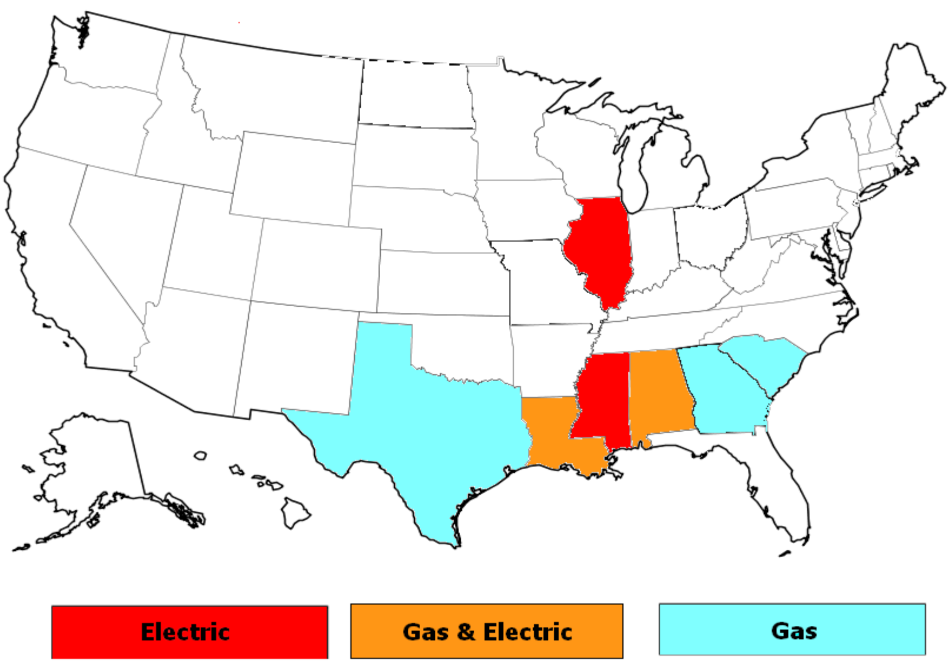
Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
Current					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2006-open	Dockets No. 18117 and 18416 (October 2005)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2008-2014	Dockets No. 18406 and 18328 (December 2007)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2009-2013	Docket 28101 (December 2009)
GA	Atmos Energy	Gas	Georgia Rate Adjustment Mechanism (GRAM)	2012-open	Docket 34764 (December 2011)
IL	Ameren Illinois	Power Distribution	Rate Modernization Action Plan - Pricing (Rate MAP-P)	2011-2017	Case 12-0001 (September 2012)
IL	Commonwealth Edison	Power Distribution	Rate Delivery Service Pricing and Performance (Rate DSPP)	2011-2017	Case 11-0721 (May 2012)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2006-open	Docket No. U-21484 (May 2006)
LA	Atmos Energy - Trans Louisiana Gas	Gas	Rate Stabilization Plan	2006-open	Docket No. U-28814 and U-28588 and U-28587(May 2006)
LA	Entergy New Orleans	Electric and Gas	Formula Rate Plan	2010-2012	Docket No. UD-08-03 (April 2009)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2009-present	Docket No. 05-UN-0503 (December 2009)
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	2008-open	Docket No. 07-UN-548 (December 2007)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 5 (FRP 5)	2010-open	Docket No. 2009-UN-388 (March 2010)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 5 (PEP-5)	2010-open	Docket No. 2003-UN-0898 (November 2009)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2010-open	Docket No. 201000030 (July 2010)
OK	Oklahoma Natural Gas	Gas	Performance Based Rate of Change Plan	2010-2013	Docket No. 200800348 (April 2009)
SC	Piedmont Gas	Gas	NA	2005-present	Docket No. 2005-125-G (September 2005)
SC	South Carolina Electric and Gas	Gas	NA	2005-present	Docket No. 2005-113-G (October 2005)
TX	Centerpoint Energy-Texas Coast Division	Gas	Cost of Service Adjustment Clause	2008-open	Gas Utility Docket 9791 (October 2008)
TX	Atmos Energy-Mid Texas Division	Gas	Rate Review Mechanism	2008 - conclusion of rate case to be filed on or before June 1, 2013	Various Resolutions/Ordinances across cities in service territory, including City of Fort Worth Ordinance 17989-02-2008
TX	Atmos Energy West Texas Division	Gas	Rate Review Mechanism	2009 - conclusion of rate case to be filed on or before June 1, 2013	Various Resolutions/Ordinances across cities in service territory
TX	Texas Gas Service - North Service Area	Gas	Cost of Service Adjustment Tariff	2009-open	Various Resolutions/Ordinances in service territory and Gas Utility Docket 9839 (April 2009)
Historic					
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2006	Dockets No. 18117 and 18416 (March 2002)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1998-2002	Dockets No. 18117 and 18416 (March 1998)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1990-1998	Dockets No. 18117 and 18416 (March 1990)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1990	Dockets No. 18117 and 18416 (June 1985)
AL	Alabama Power	Bundled Power Service	Rate Stabilization & Equalization Factor (Rate RSE)	1982-1985	Dockets No. 18117 and 18416 (November 1982)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2002-2007	Dockets No. 18046 and 18328 (June 2002)

Table 9 (continued)
Retail Formula Rate Plan Precedents[1]

Jurisdiction	Company Name	Services	Plan Name	Plan Term	Case Reference
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1996-2001	Dockets No. 18046 and 18328 (October 1996)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1991-1995	Dockets No. 18046 and 18328 (December 1990)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1987-1990	Dockets No. 18046 and 18328 (September 1987)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1985-1987	Dockets No. 18046 and 18328 (May 1985)
AL	Alabama Gas	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	1983-1985	Dockets No. 18046 and 18328 (January 1983)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2005-2009	Docket 28101 (June 2005)
AL	Mobile Gas Service	Gas	Rate Stabilization & Equalization Factor (Rate RSE)	2001-2005	Docket 28101 (June 2002)
LA	Atmos Energy - Louisiana Gas Service	Gas	Rate Stabilization Plan	2001-2003	Docket No. U-21484 (January 2001)
LA	Entergy New Orleans	Electric only	Formula Rate Plan	2004-2006	Docket No. UD-01-04 (May 2003)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	2006-2009	Docket No. 05-UN-0503 (October 2005)
MS	Atmos Energy Corp	Gas	Stable/Rate Rider	1992-2006	Docket 92-UA-0230 (September 1992)
MS	Centerpoint Energy Entex	Gas	Rate Regulation Adjustment Rider	1996-2007	Docket No. 96-UN-0202 (September 1996)
MS	Entergy Mississippi	Bundled Power Service	Formula Rate Plan 1 (FRP 1)	1995	Docket No. 93-UA-0301 (March 1994)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4A (PEP- 4A)	2009	Docket No. 06-UN-0511 (January 2009)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 4 (PEP-4)	2004-2009	Docket No. 03-UN-0898 (May 2004)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 3 (PEP-3)	2002-2004	Docket No. 01-UN-0826 (October 2002)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 2A (PEP-2A)	2001-2002	Docket No. 01-UN-0548 (December 2001)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1A (PEP-1A)	1992-1993	Docket 92-UN-0059 (July 1992)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan - 1 (PEP-1)	1991-1992	Docket No. 90-UN-0287 (December 1990)
MS	Mississippi Power	Bundled Power Service	Performance Evaluation Plan	1986-1990	Docket No. U-4761 (August 1986)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2008-2010	Docket No. 200800062 (July 2008)
OK	Centerpoint Energy Arkla	Gas	Performance Based Rate of Change Plan	2004-2008	Docket No. 200400187 (November 2004)

1 Table excludes some mechanisms that do not conform to our FRP definition. Some of these are called formula rate plans.

Figure 10: Current Retail Formula Rate Precedents by State



VII. Conclusions

Regulation of North American energy utilities is evolving to remedy the chronic underearning and frequent rate cases that traditional regulation tends to produce under modern operating conditions. Innovations continue, while some older forms of Altreg are again finding favor. This brief survey has not considered all noteworthy approaches to Altreg. Here are some of the other approaches that merit recognition:

- Regulatory assets can provide delayed compensation with interest for the annual cost of newly used and useful plant that doesn't automatically produce revenue.
- Attrition adjustments to rates can provide some compensation for an ongoing tendency of cost growth to exceed billing determinant growth. See, for example, a recent decision of the Washington Utilities and Transportation Commission in a rate case for Avista[9].
- Utilities can be permitted to file rate cases on a limited set of issues, such as additions to generation plant, that are salient causes of potential attrition.

The variety of Altreg approaches that have been established reflects the varied circumstances of individual utilities. Some are vertically integrated, while others are more specialized wire companies. Investment needs and trends in average use vary greatly. No single Altreg approach is right for every situation. The availability of multiple remedies for the underlying problems increases the chance that an approach has already been tried that fits the regulatory inclinations of a particular jurisdiction. Numerous precedents for an approach should raise confidence that it makes good sense under fairly common circumstances.

Taken together, the many innovations described in this survey can encourage utilities to make smart investments, reduce long run costs, and improve service quality without rate shock or unnecessarily frequent rate cases. Utilities can be encouraged to promote energy efficiency and peak load management aggressively. Regulators and stakeholders to regulation across the US should give priority attention to these options and consider which Altreg combinations work best in their situation.

[9] Washington Utilities and Transportation Commission, Dockets UE-120436/UG-120437, Order 09, December 26, 2012.

FORWARD TEST YEARS

FOR US ELECTRIC UTILITIES

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

U.S. investor-owned electric utilities (electric "IOUs") in jurisdictions with historical test year rate cases are grappling today with financial stresses that threaten their ability to serve the public well. Unit costs are rising because growth in sales volumes and other billing determinants is not keeping pace with growth in cost. Cost growth is stimulated by the need to rebuild and expand legacy infrastructure and to meet environmental and other public policy goals. In this situation historical test years, still used in almost 20 U.S. jurisdictions, can erode credit quality and condemn IOUs to chronic underearning.

This report provides an in depth discussion of the test year issue. It includes the results of empirical research which explores why the unit costs of electric IOUs are rising and shows that utilities operating under forward test years realize higher returns on capital and have credit ratings that are materially better than those of utilities operating under historical test years. The research suggests that shifting to a future test year is a prime strategy for rebuilding utility credit ratings as insurance against an uncertain future.

CHAPTER 1 (FORWARD TEST YEARS) provides an introduction to test year issues. Problems with historical test years are discussed. We explain that the "matching principle" used to rationalize historical test years assumes that cost and revenue remain balanced. This assumption doesn't hold when unit cost is rising. In a rising unit cost environment, rates based on historical test years are uncompensatory even in the year they are implemented. As a result, operating risk increases, raising the cost of obtaining funds in capital markets. Service quality may be compromised. Customers receive out of date price signals that encourage excessive consumption. The problems are aggravated when rate hearings are protracted. Utilities commonly respond with more frequent rate case filings but these raise regulatory cost, weaken performance incentives, and distract managers from their basic business while still not giving utilities sufficient attrition relief. It is unfair to expect utilities to offset revenue shortfalls produced by regulatory lag with higher productivity and unrealistic to think that they can do so. Forward test years can yield better results for utilities and their customers.

The unit cost trends of utilities are driven by conditions that are substantially beyond their control. These conditions include trends in input prices, productivity, and the average use of utility services by customers. For the matching principle to work, some combination of growth in utility productivity and average use must offset input price inflation.

Utility efforts to promote customer energy conservation slow growth in average use, thereby raising unit cost and making historical test year rates less compensatory. Forward test years can anticipate the slower growth in average use that results from utility conservation programs. They therefore help to remove utility disincentives to promote conservation aggressively.

The forecasts of costs and billing determinants that are made in a forward test year proceeding are uncertain but involve conditions that are at most two years into the future. A large part of utility cost is no more difficult to budget under forward test years than under historical test years. More volatile components of cost are often subject to true-up mechanisms. Conservative, well-reasoned methods for making forecasts are available. In a rising unit cost environment, the uncertainty of forecasts is less of a concern than the bias of historical test year rates.

Utilities seeking forward test years must be mindful of their high evidentiary burden. The following rate case measures bolster confidence.

- Provide concrete evidence as to why future test years and not historical test years are needed under current circumstances. Evidence concerning trends in the unit cost of utilities and in key unit cost drivers is especially pertinent.
- Provide cost and billing determinant data for one or more historical reference years and carefully explain methodologies for predicting cost and billing determinant changes between those years and the forward test year.
- Use forecasting methods that are transparent and based on reason but not needlessly complex.
- Routine variance reports comparing costs and billing determinants to utility forecasts can increase comfort that forecasts are unbiased.

CHAPTER 2 (TEST YEAR HISTORY) presents a brief history of test years in the United States. Historical test years became the norm in the U.S. because periods of stable or declining unit cost, made possible by slow price inflation and brisk growth in utility productivity and average use, were the rule rather than the exception in the electric utility industry prior to the late 1960s. Growth in productivity and average use have slowed enough in subsequent decades that unit cost has frequently risen. Under favorable business conditions, unit cost can still be flat for several years, making historical test years more reasonable. However, conditions like these can give way to conditions in which unit cost rises for years at a time.

Forward test years were adopted in many jurisdictions during the 1970s and 1980s as unit cost grew briskly, spurred by input price inflation and slower growth in average use and utility productivity. Unit cost growth was flat during most of the 1990s because business conditions driving unit cost growth were more favorable. Input price inflation slowed. Investment needs were more limited, as many utilities grew into capacity added during the construction cycle of the 1970's and early 1980's. Average use grew less rapidly than in the past but nonetheless increased appreciably in most years. Under these conditions, utilities were sometimes able to commit to multiyear base rate freezes.

Unit cost growth has since rebounded due to higher inflation, increased plant additions, and slowing growth in average use. Commissions in several states with historical test year traditions have recently moved in the direction of forward test years. Many of these states are in the West, where comparatively rapid economic growth has stimulated plant additions. The ranks of U.S. jurisdictions that use alternatives to historical test years have swollen and now encompass well over half of the total.

In summary, historical test years became the norm in U.S. rate cases during decades when unit cost was flat or declining due to remarkably brisk utility productivity and average use. Under contemporary conditions, in which average use grows slowly, if at all, and the productivity growth of utilities is more like that of the economy, unit cost may rise for extended periods undermining the matching principle.

CHAPTER 3 (EMPIRICAL SUPPORT FOR FORWARD TEST YEARS) presents results of some empirical research on test year issues. In original work for this paper, we calculated the unit cost trends of a sample of vertically integrated electric utilities from 1996 to 2008. Trends in business conditions that drive unit cost growth were measured. We also considered how test year policies affect credit metrics and utility operating performance.

Here are some salient results.

- The unit cost of sampled utilities was fairly stable from 1996 to 2002 but has since rebounded, averaging 2.3% annual growth from 2003 to 2008. The underlying causes of rising unit cost included higher input price inflation and capital spending and slower growth in the average system use of residential and commercial customers.
- In the three year period from 2006 to 2008 average use actually declined for the typical utility, pulled down by sluggish economic growth and government policies that encourage conservation. The decline was especially marked in states with large conservation programs.
- These results suggest that many IOUs may not be able in the future to count on brisk growth in average use by residential and commercial customers to buffer the impact on unit cost growth of input price inflation and increased plant additions. The problem will be considerably more acute in service territories where there are aggressive conservation programs.
- Utilities operating under forward test years were more profitable and had better credit ratings on average than those of utilities operating under historical test years. For example, from 2006 to 2008 utilities operating under forward test years realized an average return on capital of 9.2% and maintained a typical credit rating between A- and BBB+ whereas the utilities operating under historical test years realized an average return of 7.9% and maintained a typical credit rating between BBB and BBB-.
- Examination of recent trends in operation and maintenance ("O&M") expenses of utilities provides no evidence that historical test years encourage better cost management.

CHAPTER 4 (CONCLUDING REMARKS) provides some suggestions as to how interested regulators can get started down the road to forward test years.

1. Allow a forward test year on a trial basis for one interested utility.

2. Allow forward test years on an as needed basis when a utility makes a convincing case that rising unit costs make historical test years unjust and unreasonable.
3. Borrow one or two of the methods used in FTY rate cases to make additional adjustments to *historical* test year costs and billing determinants. For example, historical test year O&M expenses can be adjusted for forecasts of price inflation prepared by respected independent agencies. Special adjustments can be made for large plant additions that are expected to be finished in the near future.
4. Try a current test year (essentially the year of the rate case), which involves forecasts only one year into the future. Current test years can be combined with interim rate increases which are subject to true up when the rate case is finalized. A combination of a current test year and interim rates eliminates regulatory lag without the necessity of a two year forecast.

In states where regulators aren't ready to abandon historical test years but are sympathetic to the attrition problems caused by rising unit costs, alternative measures are available to relieve the financial attrition. Options include the following:

1. Make sure that historical test year calculations incorporate the full array of normalization, annualization, and known and measurable change adjustments that are used in other jurisdictions.
2. Grant utilities interim rate increases at the outset of a rate case. Even when later adjusted for the final rate case outcome, interim rates effectively reduce regulatory lag by a year.
3. Capital spending trackers can ensure timely recovery of the costs of plant additions, without rate cases, as assets become used and useful.
4. Several methods have been established to compensate utilities for acceleration in unit cost growth that results from flat or declining average system use. These include decoupling true up plans, lost revenue adjustment mechanisms, and higher customer charges.
5. Multiyear rate plans can give utilities rate escalation between rate cases for inflation and other business conditions that drive cost growth.

1. FORWARD TEST YEARS

This chapter provides an in depth discussion of test year issues. Basic test year concepts are introduced in Section 1.1. The rationale for forward test years is discussed in Section 1.2. The kinds of evidence used in forward test year proceedings are explored in Section 1.3.

1.1 BASIC CONCEPTS

1.1.1 Rate Cases

In the United States, rates for the services of energy utilities are periodically reset by regulators in litigated proceedings called rate cases. These cases typically take about nine or ten months to resolve and sometimes end in a settlement between contending parties which is approved by the regulator. The first year following approval of new rates is called the "rate year".

In a rate case, rates are reset to reflect the cost and service levels of the utility in a test year. The first step in this process is to establish a revenue "requirement" that is commensurate with a cost for service deemed reasonable for test year operating conditions. Rates are then established which recover the revenue requirement given the levels of service provided in the test year. The service levels (*e.g.* the number of customers served and the power delivery volume) are sometimes called "billing determinants".

Bills of energy utilities often contain charges to recover the cost of energy commodities (*e.g.* fuel and purchased power) procured on a customer's behalf which are separate from the charges to recover the cost of capital, labor, and other inputs used to operate their systems. The rates that recover the costs of non-energy inputs are commonly called "base" rates. Base rate revenues are sometimes called "margins".

Rates for the cost of energy procurement are commonly subject to true ups to recover the actual cost of energy procured. Base rates, on the other hand, have traditionally been reset only in rate cases. The earnings of utilities thus depend primarily on the difference between their base rate revenues and the cost of their base rate inputs.

1.1.2 Historical Test Years

Various kinds of test years are used in rate cases today. An historical test year ("HTY") is a twelve month period that ends before the rate case filing. It typically ends a few months before the filing because it is desirable for the test year to be as current as possible but it takes several months to properly account for a year of costs and take the other steps needed to prepare a rate case. The year between an historical test year and the rate year is sometimes called the “bridge year”.

The passage of time between a test year and the rate year is sometimes called “regulatory lag”.[1] The lag between an historical test year and the rate year is typically two years. A utility filing for new rates in calendar 2011, for example, would typically file in March or April of 2010 using a calendar 2009 test year. Thus, historical test year rates applicable in 2011 would typically reflect business conditions in 2009.

Regulatory lag in this case has several causes. One is the necessity of using a year of historical data in the rate case filing. Another is the time required to prepare a rate case filing. Still another is the time required to execute the rate case and reach a final decision on new rates.

Historical test year data are usually adjusted in some fashion to make rates more relevant to rate year business conditions. Costs and billing determinants are often normalized for the effects of volatile business conditions on the grounds that there is no reason to expect these conditions to be abnormal during the rate year. For example, if residential and commercial delivery volumes during an historical test year were elevated by unusually high summer temperatures, they may be statistically normalized to reflect average summer weather conditions. Other examples of abnormal events that can prompt normalization adjustments include ice storms, recessions, and extended generation plant outages.

Cost and output conditions in the historical test year may also be “annualized”. Effects may be removed, for a full year, of conditions that occurred during part of the HTY but are not expected to continue. One example would be costs reported for the HTY that pertained to years before the test year. Another would be the volume and peak demand of a large industrial customer who has closed its local operations.

Impacts of conditions that occurred only during certain months of the test year and are expected to prevail in the near future may also be annualized. For example, the value of the rate base at the end of an historical test year is sometimes assumed to be applicable for

[1] This is one of several definitions of “regulatory lag” which are sometimes used in discussions of regulation. Another is the length of time between rate cases.

the entire year for purposes of calculating depreciation and the return on rate base. If union wage rates are raised in the last month of the HTY pursuant to the terms of a labor contract, labor expenses may be adjusted so that the higher cost per employee is effective for the entire year.

Cost and output data may, additionally, be adjusted for "known and measurable" (sometimes called "imminent certain") changes that have already occurred since the historical test year or are likely to occur in the near future. For example, if a labor contract provides for an escalation in union wages in the bridge year, HTY cost may be adjusted to reflect the wage rates provided in the contract.

The adjustments made to HTY cost and billing determinants vary across jurisdictions. While all such adjustments tend to make rates more relevant to rate year conditions, the HTY adjustment process often ignores important changes in business conditions that occur between an historical test year and a rate year. Here are some typical omissions.

- Cost is usually not adjusted to reflect future inflation in the prices of materials, services, and new equipment because the extent of such inflation isn't known with certainty.
- Costs of plant additions in the bridge year and the rate year are often omitted if their completion date and/or final cost aren't known with certainty.
- Billing determinants are usually not adjusted to reflect trends that are likely to occur after the test year because these are not known with certainty.
- Adjustments for known and measurable changes are sometimes limited arbitrarily to the bridge year.

1.1.3 Forward and Hybrid Test Years

A forward or future test year ("FTY") is a twelve month period that begins after the rate case is filed. Test year cost and billing determinants must in this case be forecasted, and forward test years are for this reason sometimes called forecasted test years. Utilities in some jurisdictions file rate cases with *multiple* forward test years. In the Canadian province of Alberta, for instance, it has recently been common for utilities to file for two forward test years in a rate case.

Most commonly, a forward test year begins about the time that the rate case is expected to end. The test year is then the same as the rate year. A utility filing on April 1

2010, for instance, might use calendar 2011 as its test year on the assumption that the rate case will take nine months to complete.

Some utilities use FTYs that begin about the time of the rate case filing. This kind of test year may be called a "current" FTY. The initial filing is in this case based entirely on forecasts but some months of actual data for the test year become available in the course of the proceeding.

Utilities in some states make rate case filings using test years that encompass some months *before* the filing and some months *afterwards*. Data for all months of the test year are then likely to become available during the course of the filing. This kind of test year has been called a "hybrid" or "partial" test year.

1.2 Rationale for Forward Test Years

1.2.1 The Financial Challenge

The Key Role of Unit Cost

We have noted that the rates that result from a rate case are designed to recover a revenue requirement that equals cost in a test year. In the case of an historical test year the new rates embody business conditions that are typically about two years older than those of the rate year. Business conditions are likely to change between an historical test year and the rate year, causing both cost and revenue to differ from the HTY level. For rates to be exactly compensatory, base rate cost and revenue must differ from their HTY levels in the same proportion.

The assumption that cost and revenue remain in balance underlies the matching principle that regulators still use to rationalize historical test years. Kamershen and Paul note in a thoughtful 1978 article on regulatory lag that "Philosophically, the strict [historical] test year assumes the past relationship among revenues, costs, and net investment will continue into the future."[2] A 2003 NARUC *Rate Case and Audit Manual* states in this regard that

> When looking at an historical test year, one of the first questions asked is whether the test year is too stale to make it a reasonable basis upon which to establish rates for a future period… In looking at the months beyond the end of the test year, have the growth rates for rate base, expenses, and revenues all remained fairly close and constant, maintaining the test year relationship

[2] David R. Kamershen and Chris W. Paul II, "Erosion and Attrition: A Public Utility's Dilemma", *Public Utilities Fortnightly*, December 1978, p. 23.

> among these three elements, or has one element changed dramatically, making the test year out of kilter with current operations? If so, can this situation be resolved through adjustments to the test year?[3]

Cost in the rate year is likely to be substantially higher than cost in an historical test year. To understand why, consider that cost growth in any business can be decomposed into inflation in the prices it pays for inputs plus the growth in its output less the growth in its productivity:

growth Cost = growth Input Prices + growth Output – growth Productivity. [1]

The productivity growth of a business is typically not rapid enough to offset the combined effects of input price inflation and output growth. A recent study reported in testimony by Pacific Economics Group ("PEG") found, for example, that a national sample of U.S. power distributors averaged 1.03% annual growth in multifactor productivity ("MFP") from 1996 to 2006 whereas input price growth averaged 2.72% and customer growth averaged 1.00%.[4] The productivity trend of sampled distributors was similar to that of the U.S. private business sector but far from sufficient to offset the combined effects on cost of input price inflation and customer growth.

As for base rate revenue during the rate year, it can exceed the HTY revenue requirement only due to growth in billing determinants because rates are fixed at levels that reflect HTY conditions. Whether or not historical test year rates are compensatory thus depends critically on whether *unit* cost is stable in the sense that growth in billing determinants has kept pace with cost growth. If cost growth exceeds growth in billing determinants, unit cost will rise and HTY rates will be uncompensatory.

An element of complexity is added when it is considered that a utility offers many services and gathers revenue for each service from multiple charges, each with its own billing determinant. A bill for residential service, for instance, typically involves a flat monthly charge called a "customer" or "basic" charge and a "volumetric" (per kWh) charge. In this world of multiple billing determinants, historical test years will yield uncompensatory rates to the extent that cost growth between the test year and the rate year exceeds a *weighted average* of the growth in billing determinants, where the weight for each determinant is its

[3] NARUC Staff Subcommittee on Accounting and Finance, *Rate Case and Audit Manual*, Summer 2003.
[4] Mark Newton Lowry, *et al.*, *Revenue Adjustment Mechanisms for Central Vermont Public Service Corporation*, Exhibit CVPS-Rebuttal-MNL-2 in Docket No. 7336, June 2008.

share of the total base rate revenue. In other words, rates are uncompensatory when cost growth exceeds the growth in a billing determinant *index*. This is the definition of growth in a *unit cost index*.

The utility uses most of its base rate revenue to pay its workforce, vendors of materials and services (including construction services), bondholders, and tax authorities. The residual margin, called net income or earnings, is available to provide the company's shareholders with a return on their investments. The return on equity is the component of cost that is most at risk for non-recovery when base rate revenue falls short of cost. When historical test year rates are non-compensatory they can reduce a utility's rate of return on equity ("ROE") materially.

Unit Cost Drivers

If the unit cost growth of a utility has made new historical test year rates non-compensatory, it may fairly be asked whether utility actions could have stopped the growth and avoided the problem. Research over many years has shown that the unit cost of a utility is driven chiefly by changes in business conditions that are beyond its control. Growth in the unit cost of a utility's base rate inputs depends on inflation in the prices it pays for those inputs, growth in the productivity with which it uses the inputs, and an average use effect:

growth Unit Cost = growth Input Prices – (growth Productivity + Average Use). [2]

We discuss each of these unit cost "drivers" in turn.

Input Price Inflation Inflation routinely occurs in the prices utilities pay for labor, materials, services, and equipment. Since utilities have capital-intensive technologies, inflation in the price of capital is an especially important driver of their input price growth. The trend in the price of capital depends chiefly on trends in construction costs, tax rates, and the going rates of return on debt and equity in capital markets.[5]

Productivity The productivity growth of a utility depends on various conditions that include technological change, the realization of scale economies, and the pace of plant additions as

[5] The impact of construction cost on price inflation is complex. In setting rates, utility plant is valued in historical dollars. The cost of service thus depends on prices paid for construction in past decades. Construction costs in more recent years matter more because the corresponding assets are less depreciated. The rate base will tend, on average, to reflect construction costs more than a decade into the past. For most utilities, new investments therefore embody more than a decade of construction cost inflation compared to investments of average vintage. This is one of the reasons why unusually large plant additions can increase the rate base so substantially.

well as utility efforts to root out inefficiencies. Plant additions may boost efficiency gains in the long run but can slow them in the short run, especially if they involve major investments such as new base load generating units, advanced metering infrastructure, or an accelerated program to replace aging infrastructure. Scale economies depend on the pace of output growth and on whether the utility is so large that it has reached a minimum efficient scale at which incremental scale economies from output growth aren't available.

The ability of utilities to achieve productivity surges is limited in the short run. Since technology is capital intensive, the depreciation and return on rate base associated with older investments --- which cannot be changed in the short run --- account for a large share of the total cost of base rate inputs. A utility can increase productivity only by slowing growth in O&M expenses and plant additions. Opportunities to achieve *sustained* productivity gains often involve sizable upfront costs and net gains may not occur for more than a year. A downsizing of the labor force, for instance, may involve severance payments. The chief means for a utility to trim its cost in the very short run is to defer maintenance expenses and plant additions. Such deferrals must be followed by higher expenses in short order if service quality is to be maintained. A utility can't rely on a deferral strategy year after year when it is filing frequent rate cases.

Average Use A utility's unit cost growth also depends on the difference in the impact that its output growth has on its revenue and its cost. When output growth boosts revenue more than cost, unit cost growth slows. When output growth causes cost to rise more rapidly than revenue, unit cost growth accelerates.

A utility's output growth has different impacts on revenue and cost when two conditions are present. One is that the design of base rates doesn't reflect the drivers of base rate input cost. The other is that billing determinants tend to grow at a different rate than cost drivers.

Consider, first, whether the design of utility base rates is cost causative. The cost of a utility's base rate inputs is largely fixed in the short run with respect to system use. Cost is much more sensitive to growth in the number of customers served.[6] As for billing determinants, we have seen that utility tariffs for most services involve multiple charges. These include one or more "variable" charges that are so called because they vary with

[6] Cost growth may also depend, in the long run, on the growth in peak demand and/or the delivery volume.

system use. Volumetric charges vary with the volume of power delivered. "Demand" charges vary with the peak level of demand (*i.e.* the highest hourly volume registered during the month). There are, additionally, "fixed" charges that are so called because they do not vary with a customer's use of the system during the billing period. Chief amongst the fixed charges of electric utilities are customer charges. Residential and small business customers account for the bulk of a utility's base rate revenue because these customers account for the bulk of a utility's cost. In these customer classes, base rate revenue is drawn chiefly from volumetric charges.

Under these circumstances, the difference between the way that output growth affects revenue and cost is chiefly a matter of the difference between the trends in the volume of sales to residential and small business customers and the trends in the number of customers served. This is equivalent to the trends in the delivery *volume per customer* of these service classes, which are sometimes referred to as the trends in their average (system) use. Unit cost growth slows when average use rises and accelerates when growth in average use slows.

In the electric utility industry, as in most sectors of the economy, the productivity growth of utilities has for decades been a good bit slower than the inflation in the prices they pay for inputs.[7] The recent PEG study noted earlier, for example, found that power distributor productivity growth fell short of input price growth by about 169 basis points annually on average from 1996 to 2006.[8] Under conditions like these, the average use trends of residential and small-volume business customers play an important role in determining whether a utility's unit cost rises. If growth in average use is *brisk* (*e.g.* 1.5 to 2% annually), the difference between input price and cost efficiency growth can be offset.[9] If average use is *static*, unit cost will rise substantially even under normal inflationary conditions. If average use is *declining*, the rise in unit cost can be quite rapid.

Recent changes in state and federal policy are encouraging more electricity demand-side management ("DSM") and development of customer-sited solar resources. These policies include net metering, tighter appliance efficiency standards and building codes, and

[7] The difference is greater in periods of brisk input price inflation and smaller in periods of slow inflation, since productivity does not characteristically rise and fall with inflation.
[8] Lowry *et al.* (2008) *op. cit*.
[9] Irston Barnes wrote, for example, in a classic treatise on rate regulation, that "as an offset to such factors making for rising rates, the increased volume of business that usually accompanies an upward movement of prices may so reduce the overhead charges per unit as to make any increase in rates unnecessary". See Irston R. Barnes, *The Economics of Public Utility Regulation* (New York: F.S. Crofts, 1942).

subsidies for energy efficiency investments. Our discussion suggests that such programs can accelerate unit cost growth by slowing growth in average use. Whether or not the utility provides DSM programs, average use can become static or decline, removing a key means by which utilities have traditionally coped with input price inflation and avoided unit cost growth. The problem can be remedied by redesigning rates in ways that raise customer charges. But rate designs are regulated and regulators in the United States generally do not sanction high customer charges.[10]

Implications Our analysis suggests that the unit cost of an electric utility is likely to rise, making historical test year rates non-compensatory, to the extent that the following external business conditions prevail.

- Input price inflation is brisk.
- Utilities need to make large plant additions that temporarily slow productivity growth.
- Average use of the utility system is static or declining.

Situations in which unit cost is stable, encouraging use of historical test years, include those in which inflation is slow, utilities aren't making large plant additions, and average use is growing briskly.

A program to accelerate the replacement of aging distribution facilities provides a classic example of the non-compensatory nature of historical test year rates. Suppose that a power distributor replaces 10% of its distribution infrastructure during a year when new rates are implemented. The new plant has capacity similar to the plant replaced but reflects more than forty years of construction cost inflation. The company's rate base will rise substantially, temporarily slowing productivity growth and accelerating unit cost growth. Even with normal growth in input prices and average use a utility with rates based on historical test years may earn little return on this sizable investment for as much as two years after it becomes used and useful.

Conclusions

These results permit us to draw several conclusions concerning the reasonableness of historical test years in ratemaking.

[10] High customer charges are more common for U.S. gas utilities and for gas and electric IOUs in Canada.

1) Historical test years are rationalized by a matching principle that assumes a balance of cost and revenue. Our analysis shows that this relationship is not balanced in a rising unit cost environment.
2) An individual utility reporting that rates produced by historical test years are uncompensatory may be suspected by stakeholders of poor cost management. However, research shows that a utility's unit cost trend is determined primarily by business conditions over which it has little control. These include the trends in input price inflation, average use, and the need for plant additions.
3) In a rising unit cost environment, the ability of a utility to "take a hair cut" between the historical test year and the rate year is limited. Long term performance gains involve upfront costs. Deferment of expenses lowers cost today at the expense of higher costs in the future.
4) Absent favorable operating conditions, the rise in a utility's unit cost due to changing business conditions may be so great that it is unable to earn its allowed rate of return under historical test year rates even with normal productivity gains. As Kamerschen and Paul comment, "while a utility is never guaranteed that it will earn its authorized fair rate of return, if no allowance is made for attrition or the other explosive elements, the utility is denied a realistic opportunity of earning the permitted rate of return."[11] In this situation, rates produced by historical test years are inherently unjust and unreasonable. This can prompt the investment community to downgrade its credit valuations, not just for the subject utility but for other utilities in the same jurisdiction.
5) Firms in competitive markets have ways of coping with rising unit costs that aren't available to utilities. The prices a competitive firm receives for its products will tend to rise at the same pace as the unit cost of its industry. Firms experiencing unit cost growth in excess of growth in sales prices can always scale back their offerings. A utility, in contrast, charges prices set by regulators which may not be reflective of unit cost trends. The utility is obligated to provide service even if prices are non-compensatory due to flawed ratemaking practices.

[11] Kamerschen and Paul *op. cit.* p. 23.

6) Unit cost pressures are not constant over time. Several years of flat unit cost can give way to a sustained period of rising unit cost. Thus, historical test years can produce reasonable results for many years and then become uncompensatory for many years due to rising unit cost. A utility's success at earning its allowed ROE during a string of recent years does not necessarily mean that a forward test year isn't warranted prospectively.
7) Forward test years have major advantages over historical test years in a rising unit cost environment. Rates are more likely to reflect unit cost conditions in the rate year and are, to this extent, more just and reasonable. Customers receive better price signals. Lower operating risk reduces the utility's cost of securing funds in capital markets. This benefit is especially important in periods of large plant additions, when high borrowing costs can have an especially large impact on the embedded cost of debt.
8) Whether or not unit cost is rising, historical test years do not adjust rates for slowdowns in volume growth, between the test year and the rate year, which are due to utility conservation initiatives. They therefore dampen utility incentives to encourage conservation.

1.2.2 Uncertainty

Opponents of forward test years often stress the uncertainty of cost and billing determinant forecasts. Future costs cannot be verified. The changes in business conditions that drive unit cost growth (*e.g.* inflation and the in service dates on looming plant additions) can be hard to predict accurately. The impact that changing business conditions have on unit cost is not always well understood. Opponents also argue that utilities are incented to exaggerate future cost growth and to understate future growth in billing determinants. Cost and billing determinants in a historical test year are, meanwhile, known with certainty.

On the other hand, the projections at issue in a forward test year concern business conditions that are at most two years into the future. A large chunk of future cost, the depreciation and the return on older plant, is known with considerable certainty at the time that the forecast is made. There are many aids in the preparation of credible forecasts, as we discuss further in Section 1.3. Consider also that volatile components of a utility's unit cost (*e.g.* expenses for pensions and uncollectible bills) are often subject to trackers that reduce or eliminate the risk of bad forecasts.

Current test years involve less forecasting uncertainty because the test year is only a year into the future at the time that the rate case is filed. Actual data for some or all months of the test year become available in the course of the proceeding. The accuracy of the methods used to forecast cost and billing determinants can thus be tested against their ability to predict the actuals in some months of the test year.

FTY projections are, in any event, quickly followed by actual data, and a utility that makes forecasts that are consistently biased in its favor will find that its forecasts are discounted in ratemaking. Biased forecasts can even jeopardize a regulator's willingness to use forward test years. The other stakeholders to the rate case process have incentives to bias cost and sales forecasts in the other direction. These circumstances reduce or eliminate the bias of the forecasts on which FTY rates are ultimately based. If the forecast of future cost and output is accurate, the utility will receive revenue that is exactly equal to its cost. FTY rates will be fair to the utility and ratepayer alike, whereas historical test year rates are likely to be biased in a rising (or falling) unit cost environment.

On balance then forward test year rates, while involving some uncertainty, are likely to be more reflective of future business conditions than are historical test year rates in a rising unit cost environment. The uncertainty involved in basing rates on FTYs is no greater than that involved in rate freezes and other kinds of multiyear rate plans that are often approved by regulators. The Michigan Public Service Commission ("PSC") commented, in a recent decision on an FTY rate filing for Consumers Energy, that

> The basis for using a forward test year is to address the problem of regulatory lag between past and future costs. While the advantage of historical data is its objective and verifiable nature, it lacks the necessary forward perspective required in a changing economic environment. An historical test year is by definition not timely and may fail to adequately consider future demands….What is gained by dealing with data that is "known and measurable" can be lost in forcing a utility to operate with outdated numbers.[12]

[12] Michigan PSC *Opinion and Order*, Case U-175645, November 2009.

1.2.3 Regulatory Cost

A third consideration in weighing the advantages of historical and forward test years is regulatory cost. The net impact of forward test years on regulatory cost is difficult to assess. Forward test year rate cases typically do involve higher cost than rate cases based on historical test years because of the need for forecasts.

On the other hand, a number of the major issues in a rate case, including the depreciation rates and the rate of return on common equity, are not markedly more complicated in a forward test year proceeding. Depreciation on existing plant is easy to predict once a depreciation rate is established. Some of the more uncertain components of cost and revenue may be subject to trackers that mitigate rate case controversy. The cost of FTY rate cases falls as jurisdictions gain experience with forecasted evidence. Consider also that in a rising unit cost environment rates based on forward test years can, by reducing earnings attrition, sometimes reduce the frequency of rate cases.

1.2.4 Operating Efficiency

The effect of alternative test year approaches on utility operating efficiency is also frequently discussed in debates on test year approaches. Opponents of forward test years sometimes argue that they weaken utility incentives to operate efficiently. In a rising unit cost environment, an expectation that rates are going to be non-compensatory might encourage utilities to tighten their belts. FTY opponents also argue that a utility wishing to inflate its cost in an historical test year, in an effort to create higher rates in the rate year, would incur a real cost to do so.

On the other hand, the notion that rate cases generally weaken utility performance incentives is a central result of regulatory economics and is not confined to future test years. When a utility is operating under a series of annual rate cases with historical test years, cost savings this year lead quickly to lower rates. The fact that a forward test year involves forecasts does not in and of itself weaken performance incentives. Forward test year forecasts are often linked to actual costs in one or more historical reference years, so the utility must once again incur a real cost if it wishes to bolster its argument for higher costs in the test year.

Consider also that when unit cost is rising, the non-compensatory rates yielded by forward test years may cause utilities to file rate cases more frequently. This weakens performance incentives, and senior managers devote less time to the utility's basic business of providing quality service at a reasonable cost. Analysis by PEG Research has revealed that reducing the frequency of rate cases from one to three years increases a utility's productivity performance by about 50 basis points annually in the long run.[13] We therefore do not expect utility operating incentives to differ significantly between historical and forward test years on balance.

It is, in any event, unreasonable for stakeholders and regulators to acquiesce in non-compensatory HTY rates on the grounds that they encourage utilities to trim "fat" if the existence of fat has not been demonstrated in the rate case. J. Michael Harrison, an administrative law judge with the New York PSC, commented in this regard in a 1979 article on forward test years that

> It is reasonable to set rates conservatively when company's management or operations are significantly and demonstrably poor… Evidence of general management inadequacy, however, is rarely seen in rate cases and … management normally will be striving to improve efficiency in periods of continuously rising costs. Regulatory commissions certainly have an obligation to monitor operations and management effectiveness, but it does not appear justifiable to indulge in a presumption, absent specific evidence to the contrary, that deficient earnings can be attributed to management shortcomings rather than to unfavorable operating conditions.[14]

1.2.5 Other Considerations

Here are some additional considerations that merit note in a discussion of forward test year pros and cons.

- Forward test years encourage the utility, other stakeholders, and the Commission to focus more attention on the utility's plans for the future. Undesirable trends, such as rising costs that reflect inadequate attention to productivity growth, can be recognized and discouraged in advance of their occurrence. Budgeting is apt to play a more central role in cost management.

[13] See, for example, "Incentive Plan Design for Ontario's Gas Utilities", a presentation made by the senior author in work for the Ontario Energy Board in November 2006.
[14] J. Michael Harrison, "Forecasting Revenue Requirements", *Public Utilities Fortnightly,* March 1979, p. 13.

- Forward test year rate cases sharpen the ability of the regulatory community to undertake and review statistical analyses of unit cost trends. These same skills are useful in the design of multiyear rate plans in which rates are adjusted automatically between rate cases to reflect changing business conditions. Multiyear rate plans can reduce regulatory cost and strengthen utility performance incentives, creating benefits that can be shared with customers.

1.3 Evidentiary Basis for FTY Forecasts

Good evidence on future costs and billing determinants is critical to the effectiveness of forward test year rate cases. The New York PSC stated, in an order rejecting a forward test year for New York State Electric and Gas in 1972, that

> To justify the commission in deviating from its long-standing policy of using an actual test year adjusted for known changes, there must be a full showing that such a change is a practical necessity. This showing must encompass the twin requirements of substantial accuracy and an impending, uncontrollable diminution in profitability.

We have already discussed at some length the kinds of conditions that can cause unit cost to rise between an historical test year and the rate year. We consider here kinds of evidence used in FTY rate cases that increase the confidence of regulators that forecasts are accurate.

Linkage to Historical Data

Utilities in forward test year rate cases usually file detailed and extensive evidence concerning cost and billing determinants in one or more historical reference years.[15] Data for these years are usually subject to normalization and annualization adjustments like those used in historical test year filings. The utility will then present evidence on expected changes in cost and billing determinants between the historical reference year and the test year.[16] Cost projections are often made for the same detailed Uniform System of Account categories that are used in historical test year rate cases. J. Michael Harrison commented in this regard in his 1979 article that “the New York commission’s requirement that a verifiable nexus be established between a forecast and an historical base of actual experience is a sine qua non

[15] An historical reference year is sometimes called a “base period”.
[16] This sometimes includes a forecast of cost during the rate case year (if different), which is sometimes called the “bridge year”.

for forecasting revenue requirements. The burden of proving the reasonableness of its filing remains with the utility company."[17]

Indexation

Indexation is used by several utilities in FTY rate cases to escalate cost items for changing business conditions. Recall from Section 1.2.1 that the growth in the cost of a utility equals the inflation in the prices it pays for inputs plus the growth in its output less the trend in its productivity. The trend in the productivity of utilities tends to be similar to the growth in their output. Testimony just prepared by PEG Research for San Diego Gas & Electric reports that, for a national sample of power distributors, MFP averaged 0.88% annual growth from 1999 to 2008 while the number of customers served averaged 1.37% average annual growth.[18] An assumption that productivity growth equals output growth makes it possible to escalate cost from historical reference year(s) values by the forecasted growth in prices. This is the most common use of indexing in FTY forecasts.

The United States is fortunate to have available some of the best data in the world on utility input price trends. One company, Whitman, Requardt and Associates, has for decades published "Handy Whitman Indexes" of trends in the construction costs of both gas and electric utilities.[19] These are available for six geographic regions of the United States for detailed asset classes. Another company, Global Insight, has a *Power Planner* service that has forecasts, updated quarterly, of construction cost indexes. Global Insight also forecasts inflation in the prices of labor, materials, and services used by gas and electric utilities.[20] The materials and service ("M&S") price indexes are available for the detailed O&M expense categories that are itemized in the FERC's Uniform System of Accounts. Global Insight input price indexes have been used for many years to adjust revenue requirements in the multiyear rate plans of California gas and electric utilities.

Some utilities instead escalate O&M expenses in rate cases using familiar macroeconomic price indexes. The gross domestic product price index ("GDPPI") is often preferred for this purpose to the better known consumer price index because the GDPPI assigns less weight to price volatile commodities, such as food and energy, which do not

[17] J. Michael Harrison, *op. cit.*, p. 13.
[18] Mark Newton Lowry *et al.*, *Productivity Research for San Diego Gas & Electric*, August 2010.
[19] Whitman, Requardt & Associates LLP, "The Handy-Whitman Index of Public Utility Construction Costs".
[20] A discussion of an early use of detailed inflation forecasts in ratemaking is found in Michael J. Riley and H. Kendall Hobbs, Jr. "The Connecticut Solution to Attrition", *Public Utilities Fortnightly*, November 1982.

loom large in base rate input costs. Our research over the years has found that the GDPPI and CPI both tend to understate escalation in the prices of utility O&M inputs. One reason is that they are measures of inflation in the economy's prices of final goods and services and therefore reflect the productivity growth of the U.S. economy, which has been substantial in recent years. In a recent report for Hawaiian Electric, for instance, PEG found that from 1996 to 2007 the GDPPI averaged 2.21% average annual growth whereas an index of the O&M input prices paid by HECO averaged 3.05% average growth.[21] The GDPPI should therefore inspire confidence as an O&M escalator that often yields reasonable results for customers.

Simple Trend Analyses

Simple approaches to forecasting based on historical trends can, if well designed, strike a reasonable balance between the desire of regulators for accuracy and simplicity. For example, a given cost item can equal its adjusted value in the historical reference year, plus a one or two-year escalation for the average annual growth of this cost for a group of peer utilities in recent years. This approach is more sensible to the extent that the recent inflation, productivity, and output trends of the peers are similar to those that the subject utility will experience in the near future. A refinement on this general approach would be to assume a trend in cost *per customer* equal to the recent historical trend of peer utilities and then to reach cost by adding a forecast of the utility's own customer growth. Simple methods like these have counterparts for the forecasting of billing determinants. For example, the volume of residential sales in a future test year can be forecasted as the expected number of customers multiplied by the expected volume per customer, where the latter is allowed to differ from the normalized value(s) in the historical reference year(s) by its normalized trend in the last three years.

Budgeting

Some utilities use the same figures in forward test year filings that they use in their own budgeting process.

[21] Mark Newton Lowry *et al.*, *Revenue Decoupling for Hawaiian Electric Companies*, Pacific Economics Group, January 2009. pp. 65-66.

Econometric Modeling

Econometric modeling is used by several utilities in FTY cost and billing determinant projections. In an econometric model, the variable to be forecasted is posited to be a function of one or more external business conditions. Model parameters are estimated using historical data on the variable to be forecasted and the business conditions. A rich theoretical and empirical literature is available to guide model development. Given forecasts of the business conditions, the model can forecast how cost will grow between one or more historical reference years and the forward test year.

Benchmarking

Utilities can bolster the confidence of regulators in their FTY cost forecasts by benchmarking them using data from other utilities. A variety of benchmarking methods are available, ranging from econometric modeling to peer group comparisons that use simple unit cost metrics. Public Service of Colorado, for instance, recently filed a study in an FTY rate case filing that benchmarked their non-fuel O&M expense forecast.[22] The study used an econometric benchmarking model as well as unit cost metrics for a Western Interconnect peer group. The authors found that the forecasted expenses reflected a high level of operating efficiency.

[22] See Public Service Company of Colorado's Exhibit MNL-1 in docket 09AL-299E before the Public Utilities Commission of Colorado, filed October 13, 2009.

2. TEST YEAR HISTORY AND PRECEDENTS

2.1 A BRIEF HISTORY

Few states have laws on the books that mandate a particular test year approach. Statutes instead commonly feature more general provisions on regulation such as guidelines that rates be just and reasonable, that terms of service be non-discriminatory, and that service be of good quality. Flexibility with respect to test years is also encouraged by the Supreme Court's influential *Hope* decision, which held that

> The Commission was not bound to the use of any single formula or combination of formulae in determining rates. Under the statutory [Natural Gas Act] standard of "just and reasonable" it is the result reached and not the method which is controlling…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.[23]

Historical test years were nonetheless the norm in the early history of electric utility rate cases, and this reflects the prevalence over many years of business conditions that were conducive to slow unit cost growth. Slow price inflation was a contributing factor. Table 1 shows the history of GDPPI inflation in the United States from 1930 to 2009. It can be seen that inflation was negative in most years of the 1930s but was brisk during World War II, the immediate post war years, and in 1951. After the Korean War, the table shows that GDPPI inflation averaged only 1.74% annually in the 1952-1965 period.

Table 1 also shows the trend in the MFP index for the electric, gas, and sanitary sector of the U.S. economy. This index was computed by the U.S. Bureau of Labor Statistics ("BLS") for many years and was sensitive to the productivity trend in the electric utility industry due to the industry's disproportionately large size. It can be seen that the productivity growth of the electric, gas, and sanitary sector was extraordinarily rapid during the 1952-65 period, averaging 4.13% per annum. This was more than double the MFP index trend for the U.S. non-farm private business sector as a whole.

Under these favorable operating conditions, the unit cost of the electric utilities was typically stable or declining.[24] Rate cases were rare and historical test years were the norm in the rate cases that did occur. Regulators gained confidence that the matching principle could

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[23] 320 U.S. 591.
[24] See Paul Joskow, "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation", *Journal of Law and Economics*, 1974 for an insightful discussion of some of this history.

Table 1

U.S. Inflation and Productivity Trends

	GDP Price Index		Multifactor Productivity: Private Non-Farm Business		Multifactor Productivity: Electric, Gas & Sanitary Sector	
Year	Index	Growth	Index	Growth	Index	Growth
1929	10.6		NA	NA	NA	NA
1930	10.2	-3.94%	NA	NA	NA	NA
1931	9.2	-10.45%	NA	NA	NA	NA
1932	8.1	-12.08%	NA	NA	NA	NA
1933	7.9	-2.66%	NA	NA	NA	NA
1934	8.3	4.78%	NA	NA	NA	NA
1935	8.5	1.97%	NA	NA	NA	NA
1936	8.6	1.09%	NA	NA	NA	NA
1937	8.9	3.61%	NA	NA	NA	NA
1938	8.7	-1.90%	NA	NA	NA	NA
1939	8.6	-1.27%	NA	NA	NA	NA
1940	8.7	0.87%	NA	NA	NA	NA
1941	9.2	6.32%	NA	NA	NA	NA
1942	10.0	7.91%	NA	NA	NA	NA
1943	10.6	5.47%	NA	NA	NA	NA
1944	10.8	2.37%	NA	NA	NA	NA
1945	11.1	2.52%	NA	NA	NA	NA
1946	12.4	10.90%	NA	NA	NA	NA
1947	13.7	10.54%	NA	NA	NA	NA
1948	14.5	5.52%	53.0	NA	37.1	NA
1949	14.5	-0.06%	53.8	1.41%	37.7	1.66%
1950	14.6	0.78%	57.2	6.08%	40.5	7.20%
1951	15.6	6.66%	58.6	2.47%	44.4	9.16%
1952	16.0	2.15%	59.0	0.67%	46.3	4.19%
1953	16.2	1.26%	59.9	1.59%	48.1	3.80%
1954	16.3	1.01%	59.9	-0.12%	50.0	4.01%
1955	16.6	1.42%	62.4	4.15%	53.9	7.41%
1956	17.1	3.39%	61.6	-1.33%	56.6	4.99%
1957	17.7	3.44%	62.3	1.11%	58.7	3.59%
1958	18.1	2.28%	62.4	0.29%	60.3	2.71%
1959	18.3	1.13%	65.2	4.35%	64.1	6.10%
1960	18.6	1.39%	65.5	0.51%	66.0	2.95%
1961	18.8	1.12%	66.6	1.54%	67.7	2.41%
1962	19.1	1.36%	68.9	3.46%	70.9	4.68%
1963	19.3	1.05%	70.8	2.68%	72.3	2.02%
1964	19.6	1.54%	73.5	3.72%	76.1	5.02%
1965	19.9	1.80%	75.6	2.82%	79.2	4.00%
1966	20.5	2.80%	77.7	2.82%	82.4	4.07%
1967	21.1	3.03%	77.8	0.06%	85.0	3.01%
1968	22.0	4.16%	79.8	2.56%	88.8	4.42%
1969	23.1	4.82%	79.2	-0.76%	91.2	2.69%
1970	24.3	5.14%	78.8	-0.50%	92.7	1.56%
1971	25.5	4.88%	81.3	3.11%	93.8	1.21%
1972	26.6	4.22%	83.7	2.87%	95.4	1.70%
1973	28.1	5.39%	86.1	2.87%	97.2	1.88%
1974	30.7	8.66%	83.2	-3.35%	94.0	-3.31%
1975	33.6	9.06%	83.6	0.43%	94.2	0.18%
1976	35.5	5.58%	86.8	3.77%	95.4	1.28%
1977	37.8	6.17%	88.1	1.46%	95.2	-0.25%
1978	40.4	6.78%	89.4	1.47%	95.1	-0.04%
1979	43.8	7.99%	88.8	-0.67%	94.0	-1.21%
1980	47.8	8.75%	86.9	-2.20%	93.5	-0.53%
1981	52.3	9.01%	86.5	-0.42%	93.5	0.04%
1982	55.5	5.92%	83.5	-3.59%	92.6	-1.04%
1983	57.7	3.87%	86.6	3.68%	91.4	-1.23%
1984	59.8	3.69%	88.7	2.35%	94.5	3.34%
1985	61.6	2.98%	89.2	0.65%	94.4	-0.16%
1986	63.0	2.20%	90.6	1.47%	94.7	0.35%
1987	64.8	2.76%	90.7	0.16%	94.8	0.04%
1988	67.0	3.38%	91.7	1.04%	98.5	3.84%
1989	69.5	3.71%	91.7	0.00%	98.9	0.44%
1990	72.2	3.80%	92.0	0.40%	100.4	1.49%
1991	74.8	3.47%	91.3	-0.80%	100.2	-0.18%
1992	76.5	2.35%	93.5	2.39%	100.0	-0.21%
1993	78.2	2.18%	93.7	0.18%	102.6	2.52%
1994	79.9	2.08%	94.4	0.78%	103.2	0.67%
1995	81.5	2.06%	94.5	0.09%	105.6	2.22%
1996	83.1	1.88%	95.8	1.42%	106.9	1.24%
1997	84.6	1.76%	96.5	0.66%	106.9	-0.02%
1998	85.5	1.12%	97.7	1.28%	107.0	0.11%
1999	86.8	1.46%	99.0	1.27%	NA	NA
2000	88.6	2.15%	100.0	1.05%	NA	NA
2001	90.7	2.24%	100.4	0.39%	NA	NA
2002	92.1	1.60%	102.5	2.08%	NA	NA
2003	94.1	2.13%	105.2	2.60%	NA	NA
2004	96.8	2.80%	108.0	2.60%	NA	NA
2005	100.0	3.28%	109.3	1.26%	NA	NA
2006	103.3	3.21%	109.9	0.51%	NA	NA
2007	106.2	2.82%	110.1	0.21%	NA	NA
2008	108.5	2.11%	111.4	1.13%	NA	NA
2009	109.7	1.16%	NA	NA	NA	NA
Averages 1952-1965		**1.74%**		**1.82%**		**4.13%**
1973-1981		**7.49%**		**0.37%**		**-0.22%**
1982-1991		**3.58%**		**0.54%**		**0.69%**
1992-2003		**1.92%**		**1.18%**		**NA**
2004-2008		**2.84%**		**1.14%**		**NA**

yield just and reasonable rates.

The unit cost growth of electric utilities accelerated in the late 1960s and remained high for about two decades thereafter for several reasons.

- Price inflation accelerated, spurred initially by the Vietnam War and subsequently by the oil price shocks of 1974-75 and 1979-80. During the 1973-81 period, GDPPI inflation averaged 7.49% annually. Inflation thereafter slowed but still averaged 3.58% annually during the 1982-91 period.
- Rising utility rates and slowing economic growth slowed growth in use per customer.
- Utility productivity growth, far from keeping pace with inflation, slowed substantially falling by 0.22% annually on average in the 1973-1981 period and averaging only 0.69% annual growth in the 1982-91 period. Factors contributing to the slowdown included the exhaustion of scale economies by some of the nation's larger electric utilities and the propensity of some utilities to continue making major plant additions despite slower demand growth.

Under these changed conditions, utilities in the two decades after 1967 sought financial relief by filing frequent rate cases. However, many utilities found that they could not earn their allowed ROE under newly established rates. One author commented in 1974, a particularly bad year, that "it would be difficult, if not impossible, to find a utility which has been able in the first year in which a rate increase was in effect to earn the return on which the rate increase was predicted".[25] A study found that the earned ROE on equity in the electric utility industry was more than 200 basis points below the allowed rate of return on average in 1974, 1979, and 1980.[26] Interest coverage fell markedly for many utilities, limiting their ability to issue new debt. Financing of new investments required greater reliance on issuance of new common stock, and the value of stock fell below the book value of assets in many cases. Articles about attrition and regulatory lag appeared with regularity in the trade press.[27]

[25] W. Truslow Hyde, "It Could Not Happen Here – But it Did", *Public Utilities Fortnightly*, June 1974.
[26] Walter G. French, "On the Attrition of Utility Earnings", *Public Utilities Fortnightly*, February 1981.
[27] See, as another example, Theodore F. Brophy, "The Utility Problem of Regulatory Lag", *Public Utilities Fortnightly*, January 1975.

Regulators responded to this situation with an array of measures, some of which had been used at one time or another in the past. The measures included interim rate increases; the inclusion of construction work in progress ("CWIP") in rate base; more widespread use of fuel adjustment clauses; the addition of an "attrition allowance" to the target ROE, and more widespread use of forward and hybrid test years. Adopters of FTYs in these years of brisk unit cost growth included the Federal Energy Regulatory Commission ("FERC") and state commissions in California, Connecticut, Florida, Georgia, Hawaii, and New York.

Some of these states initially experimented with hybrid test years which, as we have noted, make it possible to update rate filings as actual data for the later months of the test year become available. J. Michael Harrison explained in his 1979 article some grounds for dissatisfaction with hybrid test year experiments:

> Parties charged with testing or contesting a utility's rate case presentation were faced with figures and issues that changed and shifted through all phases of the case. Even after their direct evidentiary presentations were made, these parties were faced with a required reevaluation of their positions and the possibility that a host of new issues would be created by emerging actual data. The commission staff, which in New York bore the brunt of this burden, faced an almost impossible task of analyzing new data, even as its case went to the administrative law judge or commission for decision. It became clear that the value of the already completed hearings was being seriously undermined. [28]

The New York Commission decided in 1977 to move to fully forecasted test years consisting of the first twelve months expected under the new rates.[29]

The need for forward test years subsided with the slowdown of unit cost growth that occurred in the electric utility industry in the 1990s. This slowdown was driven primarily by a partial reversal of the business conditions that had previously caused brisk unit cost growth. During the 1992-2003 period GDPPI growth averaged only 1.92% per year. Yields on newly issued long term bonds fell substantially as the market lowered its expectation of future inflation. The productivity growth of the electric, gas, and sanitary sectors increased modestly, averaging 0.94% annually during the 1992-98 period, a trend similar to that of the private business sector. One reason for the productivity rebound was a slowdown in plant additions as the industry increased utilization of the generation and transmission capacity

[28] J. Michael Harrison, *op. cit.*, p. 12.
[29] New York Public Service Commission, "Statement of Policy on Test Periods in Major Rate Proceedings", November 1977.

built in the previous twenty years. Several electric utilities operated under base rate freezes during these years. Their willingness to agree to freezes reflected in part the generally favorable unit cost conditions but sometimes also reflected an expected spurt of productivity growth due to participation in mergers or acquisitions.

Interest in forward test years has renewed for electric utilities in recent years due to a renewed growth in unit cost, which is discussed in more detail in Section 3.1 below. We note here that general inflation accelerated after 2003, with GDPPI growth averaging 2.84% annually during the 2004-2008 period. Inflation slowed in 2009 but will likely rebound as the world economy recovers from the recession. Utility investment needs increased during the period to replace aging facilities, reverse declining generation capacity margins, implement "smart grid" technologies, and meet the rising demand for transmission services to reach remote sources of renewable energy and promote bulk power market competition. Growth in average use has slowed with slowing economic growth and new initiatives to promote energy conservation.

Interest in forward test years has been especially keen in the American west. Brisk economic growth in most western states has increased the need for plant additions. Here is a brief summary of changing test year policies in selected states.

Colorado

In Colorado, the commission rejected an FTY request by Public Service of Colorado in 1993 but acknowledged that "the purpose of a test year is to provide, as closely as possible, an interrelated picture of revenue, expense, and investment reasonably representative of the interrelationships that will be in place at the time the new rates proposed in a rate case will be in effect".[30] The commission did not forbid FTY evidence and encouraged the company to consider a *current* test year, an option that it said "might provide a promising mixture of comfort and flexibility acceptable to the parties and the commission.[31]

Public Service filed FTY evidence in a 2008 rate case but the approved settlement in the case was based on historical test year evidence.[32] In May 2009, Public Service again filed FTY evidence as it sought to include in its cost of service some major plant additions,

[30] PUC Colorado Decision No. C93-1346 in Docket No. 93S-001EG, October 1993, pp. 21-22.
[31] *Ibid*, p. 40.
[32] Docket No. 08S-520E.

including a new coal-fired generating unit and a smart grid build out, which would come online in late 2009 or 2010.[33] A settlement agreement, approved with modifications, based the revenue requirement on a historical 2008 test year with extraordinary adjustments to include the cost of the impending major plant additions. The company agreed not to file a rate case for two years.

This settlement also indicated an expectation that the company would file FTY evidence in its next rate case. It commits the company to provide companion historical test year evidence, including a detailed analysis of deviations between HTY and FTY results. The Company agreed to work with interested parties on reporting requirements with respect to such deviation analyses in order to facilitate the review of future cases.

Idaho

In Idaho the largest electric utility, Idaho Power, successfully used a hybrid test year in a rate case filing in 2003. In a 2009 filing it successfully used a test year beginning in January 2009.[34] This was essentially a current FTY.

Illinois

The move to forward test years is not confined to western states. Illinois utilities have long retained the right to file FTY rate cases and Integrys recently did so successfully for its North Shore Gas and Peoples Gas Light and Coke units.[35] Peoples has a major need to increase replacement investments in its aging system, which serves Chicago.

Michigan

In Michigan, utilities have used varied test year approaches. Recent legislation (2008 PA 286) explicitly sanctions forward test year filings. The law also permits utilities to “self-implement” interim rates if rate cases aren’t resolved in 180 days. Consumers Energy and Detroit Edison have recently filed FTY rate cases successfully.

New Mexico

In New Mexico a bill was passed in 2009 that allows the state commission to use forward test years in electric and gas rate proceedings. The bill states that

[33] Docket No. 09AL-299E.
[34] Docket No. IPC-E-09-10.
[35] Dockets No. 09-0166 and 09-0167.

> In making a determination of just and reasonable rates of a utility, the commission shall select a test period that, on the basis of substantial evidence in the whole record, the commission determines best reflects the conditions to be experienced during the period when the rates determined by the commission take effect. If a utility proposes a future test period, a rebuttable presumption shall exist that a future test period best reflects the conditions to be experienced during the period when the rates determined by the commission take effect.[36]

The Bill was supported by majority voice vote of the New Mexico Public Regulation Commission. Public Service of New Mexico recently filed an FTY rate case.

Utah

Utah statutes were amended in 2003 to allow hybrid and forward test years for gas and electric utilities. The amended statutes state that

> If in the commission's determination of just and reasonable rates the commission uses a test period, the commission shall select a test period that, on the basis of the evidence, the commission finds best reflects the conditions that a public utility will encounter during the period when the rates determined by the commission will be in effect.[37]

The choice of a test year has since become an issue in the early stages of rate cases. In 2004, for example, PacifiCorp [d/b/a Rocky Mountain Power ("RMP")] filed a rate case based on a forward test year. It defended the FTY on the grounds that its costs were increasing due to rapid system growth and a plan to improve system reliability. An unopposed Test Year Stipulation acknowledged that the FTY was the most sensible test year for this case and provided for a task force to address test period procedural issues. The terms of the stipulation were not binding for future proceedings. The Commission commented in its order approving the stipulation that

> Each case needs to be considered on its own merits and the test period selected should be the most appropriate for that case. The test period selected for a utility in a particular case may not be appropriate for another utility or even the same utility in a different case. Some of the factors that need to be considered in selecting a test period include the general level of inflation, changes in the utility's investment, revenues, or expenses, changes in utility services, availability and accuracy of data to the parties, ability to synchronize the utility's investment, revenues, and expenses, whether the utility is in a cost

[36] New Mexico Senate Bill 477, 2009.
[37] Utah Code Annotated Section 54-4-4 (3).

> increasing or cost declining status, incentives to efficient management and operation, and the length of time the new rates are expected to be in effect.[38]

In December 2007, RMP filed a rate case based on a forward test year beginning in July 2008.[39] The Commission instead chose a current FTY beginning in January 2008. The Company was compelled to update its testimony to reflect the sanctioned test year. In its final decision in the case, the Commission instructed the Company to file a semi-annual "variance report" comparing its actual operating results to its rate case forecasts.

In April 2009, RMP filed a notice of intent to file a rate case in June 2009 based on a forward test year beginning in January 2010. A high level of capital investment was emphasized in advocating the need for an FTY. The Commission approved a Test Period Stipulation providing for a current FTY beginning in June 2009. The decision notes that the Division of Public Utilities argued in support of the stipulation that

> the stipulated test period, combined with the opportunity for the Company to request alternative cost recovery treatment for major plant additions, will balance the interest of the Company in reducing regulatory lag and the interests of customers by reducing the risks associated with the timing and cost of major capital additions projected to be completed 18 months into the future.[40]

Wyoming

In Wyoming, a stipulation approved in 2006 provided that RMP (d/b/a PacifiCorp) could, on a one time trial basis, file a rate case based on a forward test year. RMP filed a rate case in June 2007 using an FTY ending in August 2008. The Wyoming Public Service Commission approved a rate settlement based on the forecasts for this test year. They indicated a willingness to hear forward test year evidence in the general rate case but required the company to submit conventional historical test year evidence as well. The Commission also directed the company to prepare a report comparing its actual cost and billing determinants for the current test year to those which the company forecasted in the proceeding. In the event, the variance report stated that the company had overestimated its

[38] Public Service Commission of Utah, "Order Approving Test Period Stipulation", Docket 04-035-42, October 2004.
[39] Public Service Commission of Utah, "Order on Test Period", Docket No. 07-035-93, February 2008.
[40] Public Service Commission of Utah, "Report and Order on Test Period Stipulation", Docket No. 09-035-23, June 2009.

cost by a small amount but overestimated its revenue and on balance did not earn its allowed rate of return for the year.

In July 2008, RMP filed a new rate case with a current FTY ending in June 2009 using calendar 2007 as a historical reference year. The company emphasized in its case the inability of historical test year rates to compensate the utility for sizable new investments in its system. The Commission approved a settlement that included a provision that RMP file historical test year evidence as well as any FTY evidence in its next rate proceeding.[41] RMP will continue to file operating results that will permit the Commission to review the accuracy of its FTY forecasts.

2.2 Current Status

Table 2 and Figure 1 detail the test year approaches that are currently in use across the United States. It can be seen that historical test years are now used by most large IOUs in less than twenty U.S. jurisdictions. Nearly as many jurisdictions (AL, CA, CT, FL, GA, HI, ME, MI, MN, MS, NY, OR, RI, TN, WI, and the FERC) use forward test years routinely, at least for larger utilities. Forward test years are also used in several Canadian jurisdictions. Four jurisdictions (AR, OH, NJ, & PA) use hybrid test years. An additional 13 jurisdictions are not neatly categorized. Here are some examples.

- Large utilities in Illinois, Kentucky, Maryland, and North Dakota utilities use various test years.
- As previously noted, test years used by utilities in Utah and Wyoming depend on conditions at the time of filing and New Mexico is heading in that direction.

2.3 Conclusions

In Section 1.2 we noted that the matching principle used in historical test year rate cases is based on the assumption that growth in billing determinants matches cost growth so that unit cost is stable. This is true when growth in utility productivity and average use somehow combine to offset the cost impact of input price growth. We report in this chapter that conditions like these have not been normal for electric utilities since the 1960s. Periods of unit cost stability can still occur, but are apt to be followed by periods of rising unit cost.

[41] Wyoming PSC Docket Number 20000-333-ER-08 (Record No. 11824), May 2009.

Table 2

Test Year Approaches of U.S. Jurisdictions

Forward (16)

State	Notes
Alabama	Alabama Power's Rate Stabilization and Equalization Factor is forward looking.
California	
Connecticut	Cost is based on a historical test year that is escalated to a future rate year.
FERC	Rate cases use forward test years while formula rate plans tend to use HTYs.
Florida	
Georgia	
Hawaii	
Maine	Cost is based on a historical test year that is escalated to a future rate year.
Michigan	
Minnesota	
Mississippi	
New York	
Oregon	
Rhode Island	Cost is based on a historical test year that is escalated to a future rate year.
Tennessee	
Wisconsin	

Hybrid (4)

State	Notes
Arkansas	
Ohio	
New Jersey	
Pennsylvania	

Transitional/Varying (13)

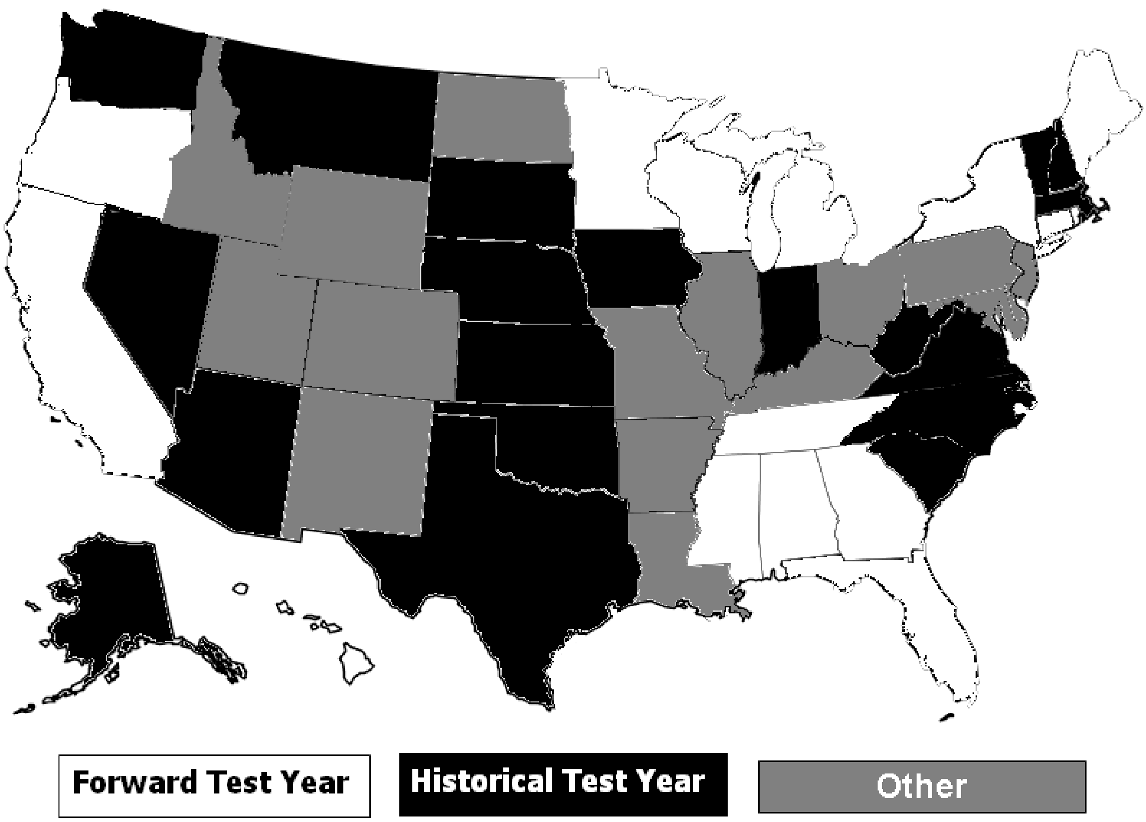
Utility Name	Notes
Colorado	Public Service of Colorado can file FTY evidence. No FTY rates have yet been approved but the most recent case made extraordinary HTY adjustments.
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently.
Delaware	Before restructuring FTY filings were common, but companies have used HTY in recent filings.
Idaho	
Illinois	Historic test years are the norm in IL. However, utilities have the right to make FTY filings and an FTY was accepted in a recent rate case of the Integrys gas utilities.
Kentucky	FTYs are legally authorized, but only Duke Energy has utilized them to date.
Louisiana	Cleco Power frequently uses hybrid test years. Entergy New Orleans recently had a hybrid test year approved via settlement.
Maryland	Baltimore Gas & Electric tends to file hybrid test years while other utilities tend to file historical test years.
Missouri	Utilities have the option to file hybrid year forecasts that are trued up during the course of the proceeding.
New Mexico	Recently passed law allows for use of FTY, but no rate case with an FTY has yet been approved.
North Dakota	Utilities use various test years including FTYs.
Utah	Test year selection is part of the rate case and can be contested. Several recent rate cases have used FTYs.
Wyoming	Rocky Mountain Power has recently had FTYs approved.

Historical (19)

Utility Name	Notes
Alaska	
Arizona	
Indiana	
Iowa	
Kansas	
Massachusetts	
Montana	
Nebraska	Nebraska has no electric IOUs in its jurisdiction. Gas companies are legally authorized to use FTYs, but no gas company has had FTY rates approved.
Nevada	
New Hampshire	
North Carolina	
Oklahoma	
South Carolina	
South Dakota	
Texas	
Vermont	
Virginia	
Washington	
West Virginia	

Figure 1

Map of Jurisdictions by Approved Test Year



Numerous regulators have moved away from historical test years in periods when unit cost is rising. Historical test year jurisdictions are now in the minority.

3. EMPIRICAL SUPPORT FOR FORWARD TEST YEARS

3.1 UNIT COST TRENDS OF U.S. ELECTRIC UTILITIES

In Section 1.2 we detailed the key role that the trend in the unit cost of utilities has in determining the reasonableness of historical test years and the need for forward test years. In original research for this paper, we have calculated the unit cost trends of a sample of vertically integrated electric utilities ("VIEUs"). In this section, we explain our research methods in some detail before discussing the results.

3.1.1 Data

The primary source of utility cost date used in the study was the FERC Form 1. Major investor-owned electric utilities in the United States are required by law to file this form annually. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Details of these accounts can be found in Title 18 of the Code of Federal Regulations.

Unit cost calculations also require data on billing determinants. Data on the number of customers served were drawn from FERC Form 1. Data on delivery volumes were drawn from Form EIA 861. The FERC Form 1 and Form EIA 861 data used in this study were gathered by SNL Financial, a respected commercial vendor.

Data were considered for inclusion in the sample from all major investor-owned VIEUs that did not offer gas distribution service or sell or spin off the bulk of their transmission assets in recent years. To be included in the study the data were required, additionally, to be plausible and not unduly burdensome to process. Data from the thirty four companies listed in Table 3 were used in the unit cost research. The sample period was 1996-2008. The year 2008 is the latest for which the requisite data were available when the study was prepared.

Supplemental data sources were used to measure input price trends. Handy Whitman indexes were used to measure electric utility construction cost trends. Global Insight indexes were used to measure trends in the prices of electric utility materials and services. Employment cost indexes prepared by the BLS were used to measure trends in labor prices. Regulatory Research Associates data was used to measure trends in target ROEs approved by regulators.

Table 3

Utilities Included in the Unit Cost Research

Company
Alabama Power
Appalachian Power
Arizona Public Service
Black Hills Power
Carolina Power & Light
Cleco Power
Columbus Southern Power
Dayton Power and Light
Duke Energy Carolinas
Empire District Electric
Entergy Arkansas
Florida Power & Light
Florida Power
Georgia Power
Gulf Power
Idaho Power
Indianapolis Power & Light
Kansas City Power & Light
Kentucky Power
Kentucky Utilities
Minnesota Power
Mississippi Power
Nevada Power
Ohio Power
Oklahoma Gas and Electric
Otter Tail Power
PacifiCorp
Portland General Electric
Public Service Company of Oklahoma
Southwestern Electric Power
Southwestern Public Service
Tampa Electric
Tucson Electric Power
Virginia Electric and Power

Number of utilities in sample: 34

3.1.2 Definition of Unit Cost

In Section 1.2.1 we discussed a measure of unit cost growth that is relevant in the appraisal of test years. It is constructed by taking the difference between growth in the net cost of base rate inputs and the growth in an index of utility billing determinants. For each sampled utility, we calculated the total cost of base rate inputs net of taxes as the sum of non-energy O&M expenses, depreciation, amortization, and return on rate base. Non-energy O&M expenses were calculated as total O&M expenses less customer service and information expenses and energy expenses that included those for steam power generation fuel, nuclear power generation fuel, other power generation fuel, and purchased power.[42] [43]

Return on rate base was calculated as the value of the rate base times a weighted average cost of capital ("WACC"). In constructing the WACC we assumed 50/50 weights for debt and common equity. The rate of return on debt was calculated as the ratio of the interest payments of electric utilities to the value of their debt as reported on the FERC Form 1. The ROE was calculated as the average applicable allowed ROEs of electric utilities as reported by Regulatory Research Associates.[44] The rate base for each utility was calculated as its net plant value less net accumulated deferred income taxes plus the value of its fuel, material, and supply inventories.

We reduced the base rate cost thus calculated by two kinds of "non-core" revenues, as is common in the calculation of retail base rate revenue requirements. One item deducted was Other Operating Revenue. This is the revenue from miscellaneous goods and services that include bulk power wheeling. The other component of non-core revenues was an estimate of the margin from power sales for resale.[45]

The growth in the billing determinant index used in our study is a weighted average of the growth in important billing determinants of electric utilities. The determinants used in index construction were the numbers of residential, commercial, and other retail customers

[42] Customer service and information expenses were excluded because they tended to rise over the sample period due to expanding demand-side management programs. The cost of DSM programs is typically recovered using tracker-rider mechanisms.
[43] We also excluded the Other Expenses category of Other Power Supply Expenses. We believe that large and volatile commodity-related costs are sometimes reported in this category.
[44] In this calculation, we assumed that the target ROE approved for a utility in its most recent rate case was applicable until a new target ROE was approved.
[45] These margins were computed as the difference between sales for resale revenue and an estimate of the energy commodity costs used in power supply.

and the corresponding delivery volumes.[46] We weather normalized the volumes using econometric demand research. In constructing the index, the trends in the billing determinants thus assembled were weighted by our estimates of the typical shares of individual billing determinants in the base rate revenue requirements of VIEUs.[47] The estimates were drawn from a perusal of recent VIEU rate case filings.

3.1.3 Unit Cost Results

Unit Cost Trends

The average annual trends of the sampled utilities in their cost, billing determinants, and unit cost can be found in Table 4 and Figure 2. It can be seen that unit cost declined by a modest 0.78% annually on average in the 1996-2002 period as average growth in billing determinants exceeded average growth in cost. The average growth in unit cost was positive in only one year of this period. These results suggest that, under typical operating conditions, historical test years would have yielded compensatory outcomes in rate cases during this period.

In the 2003-2008 period, on the other hand, it can be seen that unit cost grew briskly, averaging about 2.31% annually. Utilities experienced unit cost growth on average in every year of the period. Cost averaged 1.98% annual growth from 1996 to 2002 and 4.36% annual growth thereafter. The normalized growth of billing determinants averaged 2.75% per annum through 2002 but only 2.05% per annum thereafter. Thus, growth in billing determinants slowed despite marked acceleration of cost growth.

Earnings Impact

To consider the earnings attrition resulting from 2.3% annual unit cost growth, consider that if the typical company in the sample earned its target ROE it would constitute about 13% of the total cost of its base rate inputs. Assuming two years of 2.3% unit cost growth, revenue based on prices reflecting only the normalized business conditions of the historical test year would be expected to result in a 4.45% base rate revenue shortfall. If there was no tax adjustment, this would reduce the return on equity by about 35%. Assuming

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[46] The retail peak demands of commercial and industrial customers are also important billing determinants but data on these were unavailable.

[47] We assigned the base rate revenue shares corresponding to demand charges to the “other retail” delivery volume, expecting that these volumes have trends that are similar to those of demand charge billing determinants.

Table 4

Trends in the Unit Cost of US Vertically Integrated Utilities

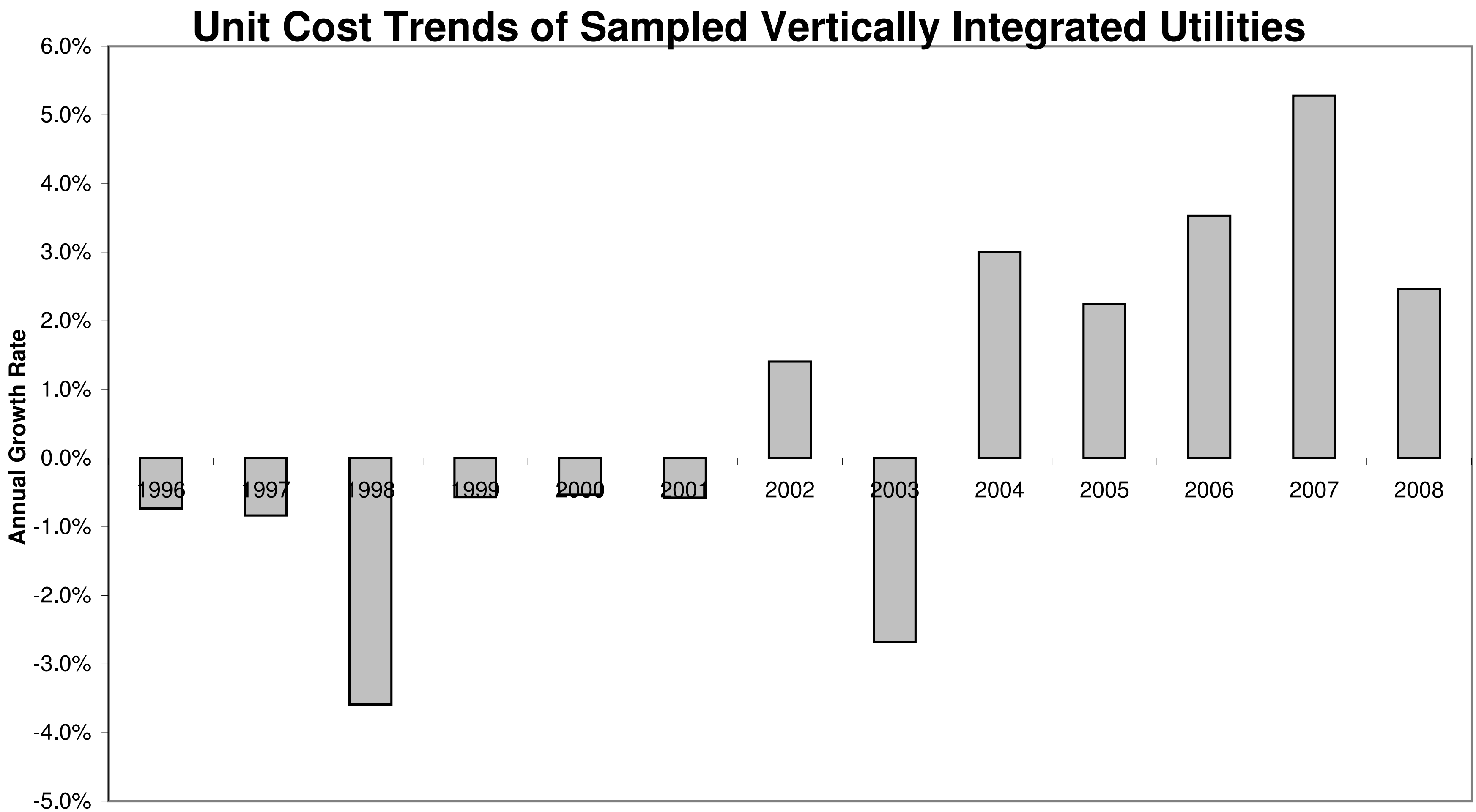
Sample Average Annual Growth Rates, Unweighted

Year	**Cost**[1]	**Billing Determinants**[2]	**Unit Cost**
1996	2.8%	3.5%	-0.7%
1997	1.4%	2.2%	-0.8%
1998	-0.7%	2.9%	-3.6%
1999	2.5%	3.0%	-0.6%
2000	3.4%	4.0%	-0.5%
2001	0.9%	1.4%	-0.6%
2002	3.6%	2.2%	1.4%
2003	1.6%	4.3%	-2.7%
2004	4.6%	1.6%	3.0%
2005	4.0%	1.8%	2.2%
2006	5.0%	1.5%	3.5%
2007	7.9%	2.6%	5.3%
2008	3.0%	0.5%	2.5%
Average Annual Growth Rates			
1996-2008	**3.08%**	**2.43%**	**0.65%**
1996-2002	**1.98%**	**2.75%**	**-0.78%**
2003-2008	**4.36%**	**2.05%**	**2.31%**

[1] The net cost formula is (Total O&M Expenses - Energy O&M Expenses - Customer Service and Information Expenses) + (Depreciation + Amortization + WACC x Rate Base) - (Other Operating Revenues + Estimated Resale Margin). The source of the cost data is FERC Form 1.

[2] The annual growth in billing determinants is a weighted average of the growth in residential, commercial, and other retail delivery volumes and customers served. The weights are shares in the base rate revenue requirement that are typical of vertically integrated electric utilities. Volumes were weather normalized by PEG Research using econometric demand modelling. The source of the raw volume data is Form EIA 861. The source of the customer data is FERC Form 1.

Figure 2


Unit Cost Trends of Sampled Vertically Integrated Utilities
Annual Growth Rate
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
-1.0%
-2.0%
-3.0%
-4.0%
-5.0%
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008

an allowed ROE of 11%, this would mean a drop in ROE of around 375 basis points before tax adjustments. While lower income taxes would mitigate the earnings impact, we may conclude from this analysis that historical test years would have been inherently non-compensatory for a utility operating under the *typical* business conditions facing VIEUs in recent years. Results would be much worse for utilities facing more pronounced unit cost pressures due, for example, to an accelerated program of replacement capex or a large scale DSM program.

Unit Cost Drivers

Input Prices Our discussion in Section 1.2.1 contained the result that input price inflation, productivity growth, and the trend in average use were key drivers of unit cost growth. We calculated for this report indexes of the inflation in the prices of base rate inputs faced by the sampled VIEUs. The growth rates of the summary input price indexes are weighted averages of the growth rates in indexes of prices for electric utility plant and O&M labor and materials and services. The index for each utility uses as weights the share of each input group in the total cost of the company's base rate inputs.[48] The index for the price of plant was calculated from the trends in bond yields, allowed returns on equity, and the Handy Whitman Construction Cost Index for vertically integrated electric utilities in the applicable region.

Results of our input price research are presented in Table 5 and Figure 3. It can be seen that the prices of base rate inputs averaged 2.76% annual inflation in the 1996-2002 period and 3.65% inflation in the 2003-2008 period --- an increase of 89 basis points. The price acceleration was primarily in materials and services and capital. M&S price inflation averaged 2.08% annually in the 1996-2002 period and 4.31% annually in the 2003-2008 period.

[48] An input price index with cost share weights effectively estimates the impact of price inflation on cost.

Table 5

Trends in Prices of Electric Utility Base Rate Inputs, 1996-2008

	Summary Input Price Index		**Labor**		**Materials & Services**		**Capital**	
Year	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
1995	1.000		1.000		1.000		1.000	
1996	1.032	3.2%	1.033	3.2%	1.020	2.0%	1.034	3.3%
1997	1.061	2.7%	1.065	3.1%	1.042	2.1%	1.061	2.7%
1998	1.095	3.2%	1.108	4.0%	1.058	1.6%	1.098	3.4%
1999	1.114	1.7%	1.139	2.7%	1.076	1.6%	1.112	1.2%
2000	1.162	4.2%	1.193	4.6%	1.109	3.0%	1.158	4.1%
2001	1.185	1.9%	1.242	4.0%	1.135	2.4%	1.168	0.8%
2002	1.213	2.3%	1.301	4.6%	1.157	1.9%	1.186	1.5%
2003	1.246	2.7%	1.356	4.2%	1.189	2.7%	1.206	1.7%
2004	1.289	3.4%	1.428	5.1%	1.241	4.3%	1.227	1.7%
2005	1.337	3.7%	1.501	5.0%	1.303	4.9%	1.251	1.9%
2006	1.417	5.8%	1.652	9.6%	1.364	4.6%	1.303	4.1%
2007	1.451	2.3%	1.578	-4.6%	1.421	4.1%	1.352	3.6%
2008	1.510	4.0%	1.629	3.2%	1.498	5.3%	1.396	3.2%
Average Annual Growth Rate								
1996-2008		**3.17%**		**3.76%**		**3.11%**		**2.57%**
1996-2002		**2.76%**		**3.76%**		**2.08%**		**2.43%**
2003-2008		**3.65%**		**3.75%**		**4.31%**		**2.72%**

Sources

Labor — Calculated by PEG Research from BLS Employment Cost Indexes that include pensions and benefits

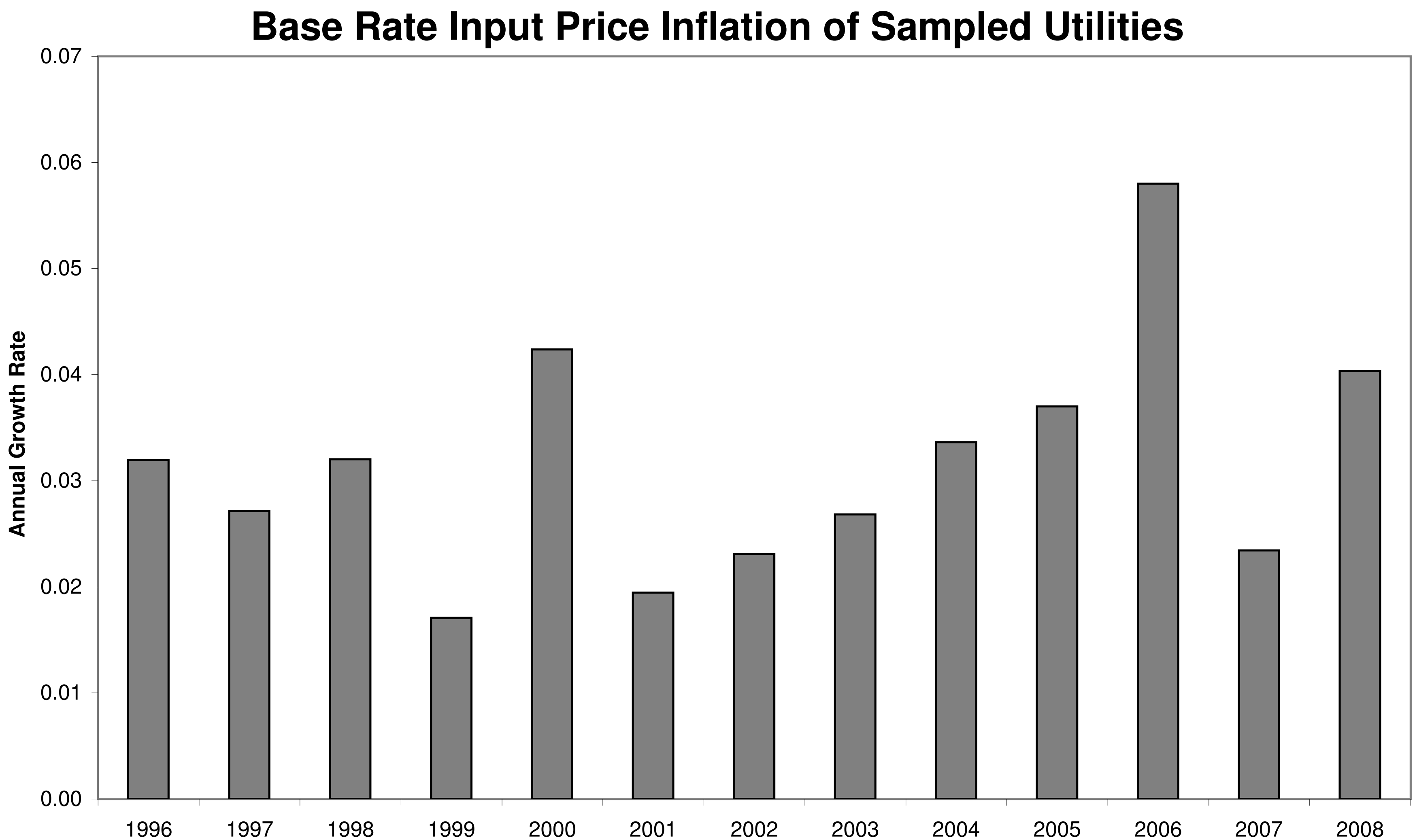
Materials & Services — Calculated by PEG Research using functional cost shares for sampled utilities obtained from FERC Form 1 and detailed electric utility M&S price indexes obtained from Global Insight's *Power Planner.*

Capital — Calculated by PEG Reseach from
- Handy Whitman electric utility construction cost indexes
- Average yields on utility bonds calculated from FERC Form 1 data gathered by SNL Interactive
- Applicable allowed ROEs as reported by Regulatory Research Associates

Summary — Calculated by PEG Research from the labor, M&S, and capital price indexes using vertically integrated electric utility base rate input cost shares drawn from FERC Form 1

FERC Form 1 data gathered by SNL

Figure 3


Base Rate Input Price Inflation of Sampled Utilities
Annual Growth Rate
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0.00
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008

Plant Additions Large plant additions were noted in Section 1.2.1 to be an important driver of utility productivity growth. Table 6 and Figure 4 describe the trend in real (*i.e.* inflation adjusted) plant additions per customer of the sampled utilities. It can be seen that from 2003 through 2008, real plant additions were 25% higher on average than in the 1995-2002 period.

Average Use In Table 7 and Figure 5 we present information on the trends in weather normalized average use by the residential and commercial customers of a large sample of U.S. electric utilities from 1996 to 2008. The sample included specialized transmission and distribution utilizes as well as VIEUs. It can be seen that the growth rates in average use have tended to fall for both residential and commercial customers since 2002. The trend was more pronounced for residential customers. Growth in normalized average use of power by residential customers averaged 1.09% per year in the 1996-2002 period and 0.43% per year in the 2003-2008 period. Growth in weather-normalized average use by commercial customers averaged 1.04% per year in the 1996-2002 period and 0.74% per year in the 2003-2008 period.

The average use slowdown was especially pronounced in the 2006-2008 period. The normalized average use of residential customers averaged a slight 0.19% annual decline and average use by commercial customers was essentially flat. For this more recent period, we separately calculated trends for utilities in service territories with large DSM programs and the trends for utilities in other territories. The normalized average use by residential customers of utilities operating in territories with large DSM programs declined by a remarkable 0.68% on average.

These results suggest that the typical IOUs may not be able in the future to count on brisk growth in average use by residential and commercial customers to buffer the impact on unit cost growth of input price inflation and increased plant additions. The problem will be considerably more acute in service territories where there are aggressive conservation programs. Forward test years will be particularly uncompensatory where utilities must cope with the consequences for load of aggressive DSM programs.

Table 6

Real Plant Additions Per Customer of Sampled Utilities

	Real Additions to Plant in Service (1995=100)	Number of Customers (1995=100)	Real Additions per Customer (1995=100)
1995	100.00	100.00	100.00
1996	93.26	101.89	91.53
1997	85.99	103.99	82.70
1998	70.50	106.33	66.30
1999	89.82	108.20	83.01
2000	102.31	110.66	92.46
2001	111.46	112.80	98.81
2002	108.46	114.70	94.56
2003	148.32	116.57	127.23
2004	110.42	118.78	92.96
2005	115.52	120.98	95.49
2006	125.04	123.89	100.93
2007	149.51	125.82	118.83
2008	165.19	126.85	130.22
Averages			
1996-2002			87.05
2003-2008			110.94

Sources: Cost and cutomer data from FERC Form 1. Plant additions deflated using applicable regional Handy Whitman electric utility construction cost indexes.

Figure 4

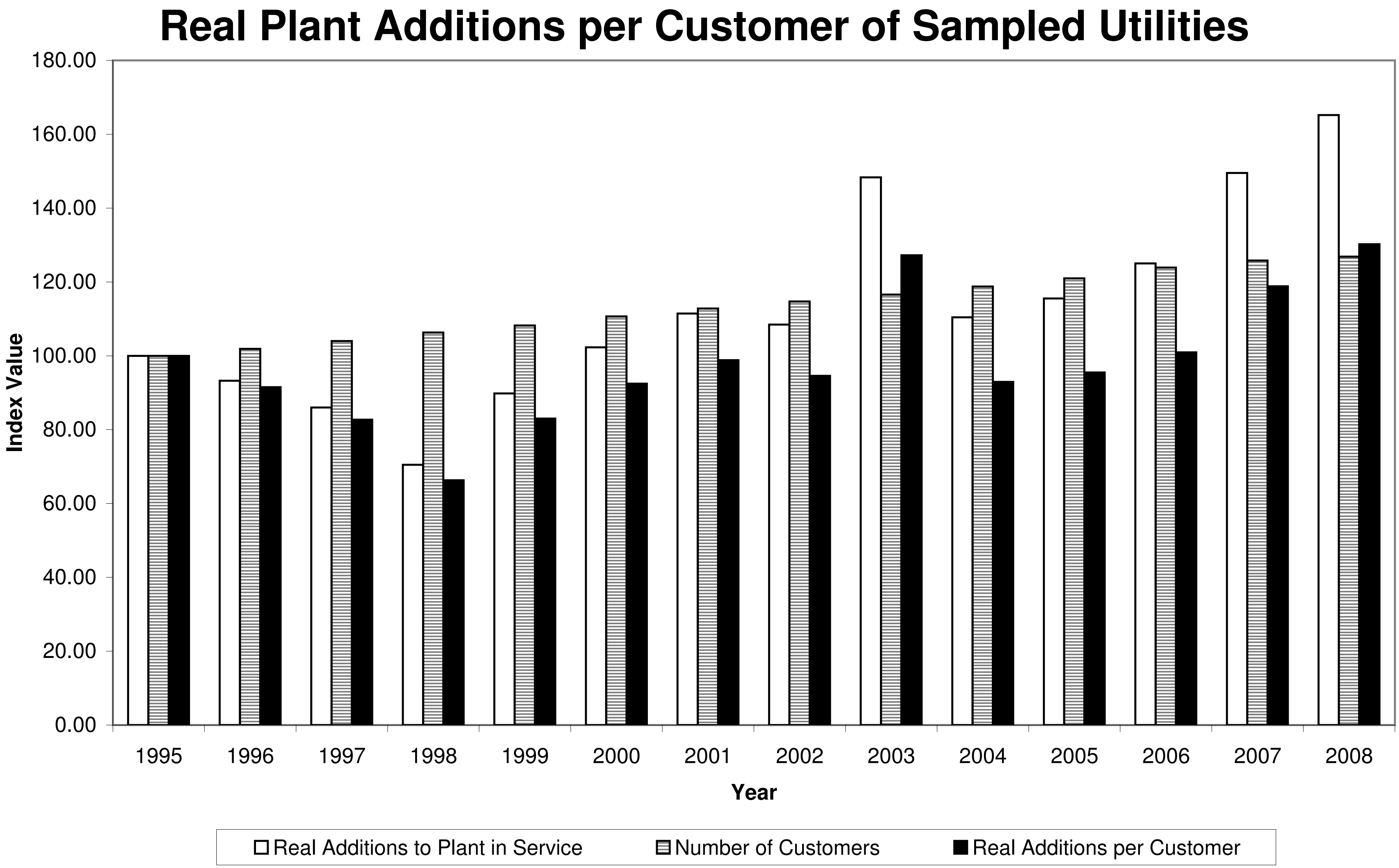

Real Plant Additions per Customer of Sampled Utilities
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Index Value
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Year
Real Additions to Plant in Service
Number of Customers
Real Additions per Customer

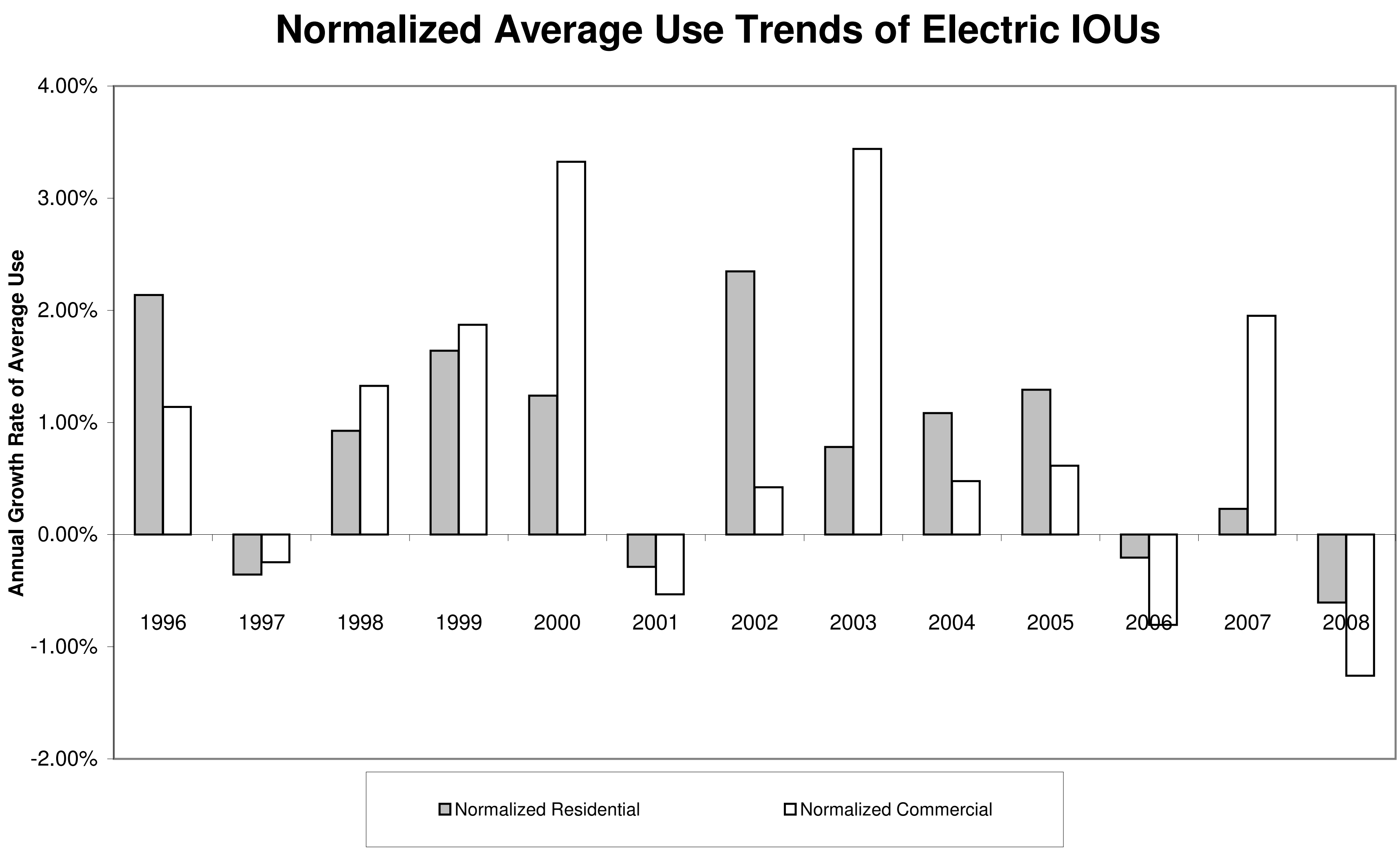
Table 7

Trends in Average Use by Residential & Commercial Customers of Investor-Owned Electric Utilities

	Residential		Commercial	
Year	Raw	Normalized	Raw	Normalized
1996	1.10%	2.14%	0.68%	1.14%
1997	-2.35%	-0.36%	-0.43%	-0.25%
1998	1.39%	0.93%	1.91%	1.33%
1999	1.66%	1.64%	1.63%	1.87%
2000	2.02%	1.24%	3.20%	3.33%
2001	-0.65%	-0.29%	-0.35%	-0.53%
2002	4.18%	2.35%	0.71%	0.42%
2003	-0.71%	0.78%	2.88%	3.44%
2004	0.03%	1.08%	0.35%	0.48%
2005	4.02%	1.29%	1.24%	0.61%
2006	-2.86%	-0.21%	-1.06%	-0.80%
2007	2.68%	0.23%	2.26%	1.95%
2008	-1.95%	-0.61%	-1.83%	-1.26%
Average Annual Growth Rate				
1996-2008	**0.66%**	**0.79%**	**0.86%**	**0.90%**
1996-2002	**1.05%**	**1.09%**	**1.05%**	**1.04%**
2003-2008	**0.20%**	**0.43%**	**0.64%**	**0.74%**
2006-2008	**-0.71%**	**-0.19%**	**-0.21%**	**-0.04%**
High DSM utilities	**-1.07%**	**-0.68%**	**-0.19%**	**-0.08%**
Other utilities	**-0.54%**	**0.05%**	**-0.22%**	**-0.02%**

Sources: Customer data from FERC Form 1. Volume data from Form EIA 861. Volumes were weather normalized by PEG Research using econometric demand modelling.

Figure 5


Normalized Average Use Trends of Electric IOUs
4.00%
3.00%
2.00%
1.00%
0.00%
-1.00%
-2.00%
Annual Growth Rate of Average Use
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Normalized Residential
Normalized Commercial

3.2 How Test Years Affect Credit Quality Metrics

Table 8 presents results for selected credit quality metrics for a large sample of electric utilities. The reported metrics are averages for the 2006-2009 period. The source is *Credit Stats: Electric Utilities—U.S.*, a report appearing in the Global Credit Portal of Standard & Poor's RatingsDirect. We present results for four credit metrics: Standard & Poor's corporate credit rating, the (rate of) return on capital, and two cash flow ratios (EBITDA interest coverage and FFO/Debt).

Cash flow ratios are used by credit analysts to assess a utility's ability to service debt. The cash flow measures are normally calculated as adjustments to net income that add back cash flows that could be used to service debt. FFO (funds from operations), for instance, adds back depreciation and amortization expenses. EBITDA (earnings before interest, taxes, depreciation, and amortization) adds back interest and tax payments as well as depreciation and amortization.

Table 8 reports averages for each of the numerical metrics for utilities that operated under historical, hybrid, and forward test years throughout the 2006-2008 period. There is also an indeterminate category for utilities that are not easily categorized as having operated under one kind of test year during this period.

Caution must be taken in making comparisons inasmuch as these metrics may differ between the sampled utilities due to differences in several other business conditions as well as to any differences in test years. The other relevant business conditions include the ability to rate base construction work in progress, the local severity of the 2008 recession, and whether or not utilities operated under formula rates and/or revenue decoupling. Despite these complications, the samples are large and diverse enough to shed some light on the effect that test years have on credit metrics.

Comparing the results, it can be seen that the values of all four credit metrics were typically much more favorable for the *forward* test year utilities than for the *historical* test year utilities.

- o The forward test year utilities had a typical credit rating between BBB+ and A- whereas the historical test year utilities had a typical credit rating between BBB- and BBB.

Table 8

How Credit Metrics of Electric Utilities Differ by Test Year, 2006-2008

Company Name	S&P Corporate Credit Rating	Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Historical Test Years		**7.9**	**4.2**	**18.2**
AEP Texas Central	BBB	6.9	2.8	8.7
AEP Texas North	BBB	8.1	4.9	21.0
Appalachian Power	BBB	6.0	2.9	9.5
Arizona Public Service	BBB-	7.3	4.6	19.3
Black Hills Power	BBB-	9.6	4.8	25.3
Carolina Power & Light	BBB+	11.3	5.9	25.0
CenterPoint Energy Houston Electric	BBB	9.8	6.2	24.4
Central Illinois Light	BBB-	9.5	8.2	29.5
Central Illinois Public Service	BBB-	4.9	3.6	15.7
Central Vermont Public Service	BB+	7.0	2.7	12.8
Commonwealth Edison	BBB-	6.4	3.1	12.1
Duke Energy Carolinas	A-	7.0	6.1	28.5
Duke Energy Indiana	A-	8.0	5.1	21.3
El Paso Electric	BBB	9.4	4.2	18.8
Entergy Gulf States	BBB	7.2	2.8	25.1
Entergy Louisiana	BBB	6.6	3.2	36.3
Entergy Texas	BBB	5.6	2.5	14.0
Interstate Power & Light	BBB+	10.5	5.5	24.4
IPALCO Enterprises (Indianapolis Power & Light)	BB+	13.2	3.4	12.9
Kentucky Power	BBB	6.5	3.5	13.8
MidAmerican Energy	A-	10.7	5.5	22.7
Nevada Power	BB	8.4	2.6	11.1
NSTAR Electric	A+	10.2	7.7	21.6
Oklahoma Gas & Electric	BBB+	10.0	6.4	25.2
Oncor Electric Delivery	BBB+	9.6	4.4	17.9
Public Service Company of Colorado	BBB+	8.1	4.3	19.6
Public Service Company of New Hampshire	BBB	8.4	4.8	13.7
Public Service Company of New Mexico	BB-	3.9	2.3	8.6
Public Service Company of Oklahoma	BBB	4.9	2.7	18.3
Puget Sound Energy	BBB	7.5	3.8	13.7
Sierra Pacific Power	BB	7.4	2.9	12.7
South Carolina Electric & Gas	BBB+	8.3	4.7	21.1
Southern Indiana Gas & Electric	A-	9.5	5.4	22.8
Southwestern Electric Power	BBB	7.4	3.5	15.4
Southwestern Public Service	BBB+	5.3	3.5	12.1
Texas-New Mexico Power	BB-	5.3	3.3	9.5
Tuscon Electric Power	BB+	8.4	3.2	17.9
Westar Energy	BBB-	6.7	3.9	14.8
Western Massachusetts Electric	BBB	5.8	3.7	11.8
Hybrid Test Years		**9.5**	**5.9**	**19.9**
Atlantic City Electric	BBB	9.6	4.4	34.2
Baltimore Gas & Electric	BBB	6.8	4.3	11.1
Cleveland Electric Illuminating	BBB	13.3	4.3	9.2
Cleco Power	BBB	8.3	3.7	10.9
Columbus Southern Power	BBB	13.5	6.5	23.3
Dayton Power & Light	A-	16.3	16.1	42.9
Duke Energy Ohio	A-	5.2	6.3	25.5
Entergy Arkansas	BBB	6.7	5.6	27.7
Idaho Power	BBB	6.6	3.8	10.7
Jersey Central Power & Light	BBB	8.3	8.5	22.9
Metropolitan Edison	BBB	9.3	6.7	12.7
Ohio Edison	BBB	9.4	4.6	14.5
Ohio Power	BBB	8.2	4.3	15.0
PECO Energy	BBB	10.5	7.0	19.5
Pennsylvania Electric	BBB	8.9	5.5	15.8
PPL Electric Utilities	A-	9.5	4.6	18.6
Public Service Electric & Gas	BBB	8.7	4.9	14.9
Toledo Edison	BBB	11.9	5.2	28.0

Table 8, continued

How Credit Metrics of Electric Utilities Differ by Test Year, 2006-2008

Company Name	S&P Corporate Credit Rating	Return on Capital (%)	EBITDA/Interest Coverage	FFO/debt (%)
Forward Test Years		**9.2**	**5.1**	**21.0**
ALLETE (Minnesota Power)	BBB+	10.8	5.1	19.5
Central Hudson Gas & Electric	A	9.6	4.9	14.9
Central Maine Power	BBB+	8.2	5.3	17.8
Connecticut Light & Power	BBB	6.7	4.3	12.2
Detroit Edison	BBB	8.2	4.9	16.8
Entergy Mississippi	BBB	7.2	4.3	27.1
Florida Power & Light	A	9.9	7.0	30.7
Florida Power Corp.	BBB+	9.9	4.5	19.0
Georgia Power	A	10.1	5.9	22.6
Gulf Power	A	9.7	5.6	19.2
Hawaiian Electric	BBB	7.1	4.4	15.3
Mississippi Power	A	11.6	8.9	35.5
Northern States Power - MN	BBB+	9.4	4.9	22.9
Northern States Power - WI	A-	8.8	5.9	26.6
Pacific Gas & Electric	BBB+	10.7	4.0	23.3
PacifiCorp	A-	7.9	4.0	17.3
Portland General Electric	BBB+	7.9	4.1	19.2
Rochester Gas & Electric	BBB	9.4	3.8	19.4
Southern California Edison	BBB+	11.4	4.0	19.3
Tampa Electric	BBB	9.6	4.5	21.0
Wisconsin Electric Power	A-	6.9	5.4	14.6
Wisconsin Power & Light	A-	10.1	5.0	24.7
Wisconsin Public Service	A-	9.8	5.6	23.8
Indeterminate		**7.8**	**4.3**	**18.1**
Alabama Power	A	9.5	5.7	21.5
Empire District Electric	BBB-	7.3	3.5	15.7
Indiana Michigan Power	BBB	6.7	3.5	15.4
Kansas City Power & Light	BBB	7.9	4.8	19.4
Potomac Electric	BBB	7.4	4.4	20.6
Southwestern Electric Power	BBB	7.4	3.5	15.4
Union Electric	BBB-	8.2	4.4	18.4
All Companies		**8.6**	**4.8**	**19.3**

Source: Standard & Poor's Ratings Direct, *Credit Stats: Electric Utilities - U.S.* August 24, 2009. Financial metrics are averages of the years 2006-2008.

- The forward test year utilities had an average return on capital of 9.2% whereas the historical test year utilities had an average return of 7.9%.
- The forward test year utilities had an average EBITDA/interest coverage of 5.1 whereas the historical test year utilities had an average coverage of 4.2
- The forward test year utilities had an average FFO/debt ratio of 21.0% whereas the historical test year utilities had an average ratio of 18.2%.

Additional insights concerning the effect of forward test years on credit quality can be found in another recent Standard & Poor's report.[49] The study sought to rank state regulatory regimes with respect to their effect on credit quality. Of the fourteen states covered by the study which had well-established forward test year traditions at the time of the study, the author found five to be "more credit supportive", six to be "credit supportive", only two to be "less credit supportive", and none to be "least credit supportive". In contrast, of the seventeen states covered by the study that had well-established historical test year conditions, only three were categorized as "more credit supportive", seven were categorized as "credit supportive", six were categorized as "less credit supportive" and one was categorized as "least credit supportive".

3.3 Incentive Impact of Forward Test Years

In Section 1.2.4 we noted that the incentive impact of forward test years has been an issue in some proceedings. We argued, based on our experience in the field of incentive regulation, that the incentive impact of forward and historical test years should be similar on balance. To test the hypothesis that the choice of a test year has no impact on operating efficiency, PEG Research measured the trends in the O&M expenses of a large group of VIEUs over the 1996-2008 sample period. O&M expenses are a better focus than the total cost of base rate inputs in such a study because some utilities had greater needs than others for major plant additions and these needs had little to do with the kind of test year in a jurisdiction. Differences in cost growth are due in part to differences in output growth, so we divided O&M expenses by three alternative output metrics: generation volumes, generation capacity, and the number of customers served. We calculated how the trends in the three cost metrics differed for utilities operating under three kinds of test years: historical, hybrid, and

[49] Todd Shipman, *Assessing U.S. Utility Regulatory Environments*, Standard & Poor's Ratings Direct, November 2008.

forward. If forward test years weaken operating efficiency, we would expect the growth in the cost metrics to be higher on average for the forward test year utilities.

Results of this exercise are reported in Table 9. It can be seen that, using all three cost metrics, the cost trends of the forward test year utilities were similar to --- and a little slower than --- those of the historical test year utilities and of the full utility sample. These results are consistent with the notion that there is no significant difference in the incentives to contain cost that are generated by future and historical test years.

Table 9

Trends in Unit Non-Fuel O&M Expenses by Test Year, 1996-2008

	Test Year Type			
	Historic	Partial	Forward	All
Cost/Customer	2.1%	2.0%	1.9%	2.2%
Cost/Generation Volume	2.2%	3.0%	1.4%	2.3%
Cost/Generation Capacity	1.9%	3.2%	1.3%	1.9%

Source: Federal Energy Regulatory Commission (FERC) Form 1 and Form EIA-876 data gathered by SNL Financial.

4. CONCLUDING REMARKS

Having established in some detail in the chapters above the financial stresses imposed on U.S. electric utilities by historical test years today, we provide in this chapter some concluding remarks on action plans for regulators who wish to move forward with sensible remedies.

4.1 SENSIBLE FIRST STEPS

In states where regulators are interested in experimenting with forward test years but not yet prepared to "make the plunge" to large scale adoption, our discussion has identified a number of cautious first steps down the road that limit the risk of bad outcomes but permit the regulatory community to learn more about FTY pros and cons.

- Allow a forward test year on a trial basis for one interested utility.
- Allow forward test years on an occasional basis when a utility makes a convincing case that rising unit costs make historical test years unjust and unreasonable. A ruling on the test year issue can precede the preparation of a rate case, as in Utah.
- Borrow a few of the methods used in FTY rate cases to make additional adjustments to *historical* test year costs and billing determinants. For example, HTY O&M expenses and/or plant addition costs can be adjusted for forecasts of price inflation prepared by respected independent agencies. Residential and commercial delivery volumes can be adjusted for recent average use trends. Special adjustments can be made for looming major plant additions.
- Try current FTYs, which involve forecasts only one year into the future. Current test years can be combined with interim rate increases at the outset a rate case which are subject to true up when new rates are ultimately approved. The combination of current test years and interim rates is a salient option because it eliminates regulatory lag without a two year forecast.

4.2 ALTERNATIVE REMEDIES FOR TEST YEAR ATTRITION

In states where regulators aren't ready to abandon historical test years but are sympathetic to the attrition problems that they sometimes cause, a variety of alternative measures are available to relieve the financial attrition that can result from using historical test years in a rising unit cost environment.

1. HTY calculations can incorporate the full array of normalization, annualization, and known and measurable change adjustments that are used in other jurisdictions.
2. Utilities can be permitted to implement interim rate increases. Interim rates can effectively reduce regulatory lag by a year. States that permit interim rates include HI, IA, MI, MO, NH, OK, TX, VA, and WI.
3. Capital spending trackers can ensure timely commencement of the recovery of costs of plant additions, without rate cases, when assets become used and useful. Trackers can be designed to maintain incentives for good capital cost management and timely project completion. Monitoring by PEG Research reveals that capital spending trackers have been approved for use by energy utilities in AR, CA, FL, GA, IA, ID, IL, IN, KS, KY, MD, ME, MN, MO, NJ, NY, OH, OK, OR, PA, TX, VA, and WI.
4. The inclusion of CWIP in rate base improves cash flow and reduces future rate shocks. This practice also reduces the losses that a utility experiences making large plant additions under historical test year rates. Monitoring by the Edison Electric Institute has found that states that have recently allowed inclusion of CWIP in rate base include CO, FL, GA, IN, KS, KY, LA, MI, MO, NC, NM, NV, SD, TN, VA, and WV.
5. Cost trackers can also adjust rates automatically to ensure timely recovery of O&M expenses that are unusually volatile and/or expected to rise rapidly. Expenses that are often recovered using trackers include those for pensions and benefits, uncollectible bills, and DSM.
6. Several methods have been established to compensate utilities for slowing growth in average use.
    - Lost revenue adjustment mechanisms (a/k/a lost margin trackers) restore margins that are estimated to have been lost because of utility conservation programs. These are currently used by electric utilities in CT, IN, KY, OH, NC, and SC.

- Decoupling true-up plans help base rate revenue track revenue requirements more closely and can thereby restore lost margins that result from slow growth in average use resulting from a wider variety of sources, including conservation programs administered by independent agencies. Such plans are currently used by electric utilities in CA, CT, DC, HI, ID, MA, MD, MI, NY, OR, VT, and WI. They are used by gas utilities in several additional states (*e.g.* AR, CO, IN, MN, NJ, NC, UT, VA, WA, and WY).
- Higher customer charges are also effective in reducing attrition from declining average use. Straight fixed variable pricing, which recovers *all* fixed costs using fixed charges, is used by gas utilities in GA, MO, OH, OK, and ND.

7. The duration of rate cases can be limited. A reasonable cap is the average length of cases in the United States, which is currently between nine and ten months.[50]
8. Multiyear rate plans can give utilities rate escalation between rate cases for inflation and other business conditions that drive cost growth. Such plans typically have a duration of three to five years, and terms of seven to ten years have been approved. Even if an historical test year makes the initial rates under such plans non-compensatory, it would only happen once in a multiyear period. Utilities would have several years to recoup their losses through superior productivity growth --- and an incentive to do so. North American jurisdictions where multiyear rate plans are common include CA, ME, MA, NY, OH, and VT in the United States and Alberta, British Columbia, and Ontario in Canada. This approach to ratemaking is more the rule than the exception overseas.

[50] See *EEI 2007 Financial Review*, p. 36.

APPENDIX: UNIT COST LOGIC

To better understand the conditions that can cause historical test year rates to produce earnings attrition, suppose that year t is a rate year (a year when new rates take effect) and that the utility is underearning with its newly implemented HTY rates. The cost of base rate inputs then exceeds base rate revenue and the ratio of cost to revenue is positive.

$$Cost_t / Revenue_t > 0.$$

To simplify the story, suppose next that the utility has only one service and the base rate for that service is gathered exclusively from a volumetric charge. In the historical test year, the revenue requirement is then the product of a price (P_{t-2}) and a volume (V_{t-2}) and this is set equal to the allowed cost of service

$$P_{t-2} \times V_{t-2} = Cost_{t-2}$$

so that

$$P_{t-2} = Cost_{t-2} / V_{t-2} = Unit\ Cost_{t-2}.$$

The rate equals the cost per kWh of sales, which we may call the *unit* cost of service in the historical test year.

Revenue in the rate year is the product of this same price, which reflects *historical* business conditions, and the *contemporary* sales volume. The ratio of cost to revenue may then be restated as

$$\begin{aligned} Cost_t / Revenue_t &= Cost_t / (P_{t-2} \times V_t) \\ &= Cost_t / [(Cost_{t-2} / V_{t-2}) \times V_t] \\ &= (Cost_t / V_t) / (Cost_{t-2} / V_{t-2}) \\ &= Unit\ Cost_t / Unit\ Cost_{t-2}. \end{aligned} \quad [A1]$$

An historical test year rate is thus non-compensatory if the utility's unit cost is higher in the rate year than it was two years ago in the test year. Growth in the unit cost of the utility is thus the fundamental reason for earnings attrition. Note also that

$$Unit\ Cost_t / Unit\ Cost_{t-2} = (Cost_t / Cost_{t-2}) / (V_t/V_{t-2}). \quad [A2]$$

Unit cost thus grows between the test year and the rate year if cost grows more rapidly than the sales volume. Growth in the sales volume therefore matters as well as cost growth in determining a utility's unit cost trend. Moreover, the ability of historical test year rates to avoid under or, for that matter, over earning depends on the stability of the relationship between cost and billing determinants.

The key result that historical test years are non-compensatory when unit cost is rising extends to the real world situation in which a utility provides multiple services, each with several charges. In this situation the ratio of the total delivery volume in [A2] is replaced by a weighted average of the ratios for all billing determinants.[51]

[51] The weight for each individual billing determinant is its share of the total base rate revenue.

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Rebuttal Exhibit
CMG-10 is
being provided in a
separate file in Excel
format.

Rebuttal Exhibit CMG-11 is being provided in a separate file in Excel format.

Rebuttal Exhibit
CMG-12 is
being provided in a
separate file in Excel
format.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	**CASE NO. 2020-00349**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	**CASE NO. 2020-00350**

REBUTTAL TESTIMONY OF
ROBERT M. CONROY
VICE PRESIDENT, STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: April 12, 2021

TABLE OF CONTENTS

I. BACKGROUND

Q. Please state your name, position, and business address.

A. My name is Robert M. Conroy. I am the Vice President of State Regulation and Rates for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to address certain intervenors' criticisms of the Companies' Rider NMS-2 proposal, refute certain testimony regarding the Companies' proposed residential Basic Service Charges, discuss intervenor concerns regarding the impacts of rate increases on low- and fixed-income customers, and address a number of rate and tariff matters raised by the intervenors. Finally, I support the positions stated in William Steven Seelye's rebuttal testimony that the Companies' proposed revenue allocations and rates, and in particular the Companies' proposed residential Basic Service Charges, are fair, just, and reasonable.

II. NET METERING

Q. Have you reviewed the intervenors' testimony concerning the Companies' net metering proposals?[1]

A. I have. Certain intervenors' testimony on these issues has created more confusion than clarity.[2] Therefore, although Mr. Seelye is addressing this topic in depth and detail in

[1] Direct Testimony of Karl R. Rábago on behalf of Joint Intervenors ("Rábago Testimony"); Direct Testimony and Exhibits of Stephen J. Baron on behalf of the Attorney General of the Commonwealth of Kentucky and the Kentucky Industrial Utility Customers, Inc. ("Baron Testimony") at 7-12; Direct Testimony of Benjamin D. Inskeep on behalf of Kentucky Solar Industries Association, Inc. ("Inskeep Testimony").

[2] Rábago Testimony; Inskeep Testimony.

his rebuttal testimony, I would like to address some fundamental issues that will help clarify the analysis and the appropriate standards to apply when considering these issues. First, I will address the separate and distinct roles of net metering customer-generators as customers versus as generators. Second, I will note that the Companies' customers, not the Companies and their shareholders, will ultimately bear the cost of compensation paid to customer-generators for energy produced onto the grid. Third, I will address the issue of legacy rights certain intervenors raised. Fourth, I will respond to comments made by Joint Intervenors witness Karl R. Rábago in Case No. 2019-00256, which have been incorporated into the record of these proceedings by reference.

A. <u>Customer-Generators Have Separate and Distinct Roles as Customers and Generators</u>

Q. What is the first and most fundamental issue you would like to address?

A. The first and most fundamental confusion certain intervenors have introduced is to conflate the roles of a net metering customer-generator, primarily by suggesting that a cost of service study is necessary to support the compensation paid to customer-generators for the non-firm, as-available energy they produce onto the Companies' distribution systems.[3] It is important to remember that a customer-generator stands in two separate and distinct relationships to the Companies: customer and generator. As a customer, a customer-generator takes service from the Companies and pays cost-of-service-based rates for the service the Companies provide. As a generator, a customer-generator acts as a supplier to the Companies whenever the customer-generator

[3] *See, e.g.,* Inskeep Testimony at 13-17; Rábago Testimony at 16 ("[T]he dramatic proposed reduction in compensation … is not based on any objective data or principled cost of service analysis ….").

provides energy onto the Companies' system, for which non-firm, as-available energy the Companies must appropriately compensate the customer-generator.

Again, these are separate and distinct roles and relationships that require two separate and distinct analyses. As a customer, the rates that are appropriate to charge a customer-generator begin with a cost-of-service analysis. As a generator, the compensation that is appropriate to provide to net metering customers requires evidence of what would be reasonable and prudent to pay for the non-firm, as-available energy customer-generators provide, bounded by market prices for similar energy offerings and consistent with the Companies' obligation to provide its customers with safe and reliable service at the lowest reasonable cost.

In these proceedings, the Companies did not propose to charge customer-generators rates that differ in amount or structure from any other similarly situated customer, so it was not necessary to provide net-metering-specific cost-of-service evidence. Rather, because the Companies proposed compensation rates for new net metering customers, they provided evidence concerning what was reasonable and prudent to pay for the non-firm, as-available energy those customer-generators may provide.

Q. Would you like to expand upon the separate and distinct roles of a customer-generator as a customer versus as a generator?

A. Yes. First and most fundamentally, as a customer, a customer-generator takes service from the Companies under Commission-approved terms and conditions and pays the Companies rates approved by the Commission for services rendered. Those rates must be fair, just, and reasonable,[4] cannot be unreasonably discriminatory,[5] and must be promulgated using procedures prescribed by Kentucky law.[6] In short, the Companies have considerable obligations to a customer-generator as a customer, and they have a right to charge fair, just, and reasonable rates for the service they provide.

And it is important to understand that the Companies' costs to serve their customers, which are the foundation of their rates, are *never* zero or less.[7] This might seem self-evident; after all, the generation, transmission, distribution, customer service, and administration systems and personnel upon which all customers rely at all times—including all net metering customers—have positive, non-zero costs. This is true even for net metering customers when they are net exporters of energy; at such times they are relying on the Companies' systems to make their exports possible, and more importantly to be ready to supply energy when the customers' net production ends, which happens unpredictably and instantaneously due to the intermittent nature of such customers' energy production and variability of their consumption. Therefore, the cost to serve all customers—including all net metering customers—is always greater than zero.

That simple, straightforward fact is why Mr. Inskeep's assertion that "[a] net metering customer can theoretically have a negative cost of service depending on the amount and timing of exports" is false.[8] Such a statement arises from conflating

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[4] KRS 278.030(1).
[5] KRS 278.170.
[6] *See, e.g.,* KRS 278.180 and 278.190.
[7] Mr. Seelye's rebuttal testimony addresses net metering customers' cost of service in greater detail. In particular, he addresses how such customers' cost of service compares to similarly situated non-generators. The purpose of my testimony in this section is to highlight that there is always a non-zero cost to serve all customers, including customer-generators.
[8] Inskeep Testimony at 13.

together a customer-generator's separate and distinct roles as customer and generator. It may be true at a given moment that the value of the energy a customer-generator is providing onto the grid exceeds the cost to serve the customer at that moment, but that is not the same as saying there is no cost or a negative cost to serve that customer at that moment.

Distinguishing between a customer-generator as a customer and as a generator helps to understand why a cost of service study has nothing at all to do with the appropriate compensation for energy net metering customers supply onto the Companies' systems. Certain intervenor witnesses have asserted that the Companies have not adequately supported their proposed Rider NMS-2 compensation rates because the Companies did not file with their applications a cost-of-service study for net metering customers.[9] The Companies are not attempting in these proceedings to create separate rate classes for net metering customers; such an effort would indeed require cost-of-service evidence.[10] The Companies have not previously proffered such evidence because it is not necessary or applicable to what the Companies have proposed to address in these proceedings, namely the wholly separate and distinct compensation rate for the energy that customer-generators, *as* generators, supply to the Companies' system, energy for which all other customers pay.

Q. How does that point relate to Mr. Rábago's assertion that "the … arrangement the Companies propose for self-generators is not applied to customers that reduce

[9] *See, e.g.,* Inskeep Testimony at 13-17, esp. at 15 ("The value of exports can only be identified with a cost-benefit study that utilizes a long term time horizon and fully accounts for all future benefits and costs."); Rábago Testimony at 16 ("[T]he dramatic proposed reduction in compensation … is not based on any objective data or principled cost of service analysis ….").

[10] In response to certain intervenors' assertions, Mr. Seelye is presenting in his rebuttal testimony cost-of-service evidence concerning residential net metering customers.

their bills through energy efficiency, energy management, or simple behavioral changes"?[11]

A. The point is this: The Companies are not asserting that net metering customers, *as* customers, should be in their own rate classes.[12] I agree with Mr. Rábago's statement that customers who use energy efficiency or conservation "are functionally identical to customers that reduce usage at the same time and at the same level as customers that self-generate" insofar as energy usage is concerned.[13] The Companies are not proposing separate rate classes for energy-efficient customers, customers who conserve energy, or net metering customers *as* customers, all of whom can indeed have similar usage characteristics. Creating separate rate classes for such customers would indeed require cost-of-service evidence to support.

But I strongly disagree with the next statement Mr. Rábago makes, which again conflates customer-generators' separate and distinct roles as customer and generator: "But only for self-generation customers do the Companies assert their obsession with reducing the economic benefits of the investment customers make in order to better control their utility bills."[14] The Companies have no such "obsession"; rather, they are seeking to ensure that the more than 99% of their customers who are not customer-generators are not forced to overpay future net metering customers for the as-available, non-firm energy customer-generators supply, after serving their own loads first, onto the Companies' grid. The Companies are not singling out net metering customers, *as*

[11] Rábago Testimony at 21.
[12] It is important to remember that net metering customers are not just residential, though much of the focus is on residential net metering customers in certain intervenors' testimony.
[13] Rábago Testimony at 21.
[14] *Id.*

customers, for special treatment in any way; rather, Rider NMS-2 will treat future net metering customers, *as* customers, just like every other customer in the same rate class. In other words, future net metering customers served under Rider NMS-2 will be able to reduce their consumption with their generation and receive the benefit of that reduced consumption at the retail rate just like any other customers who reduce consumption by any other means. In addition, they will pay for each and every kWh they consume from the Companies, just like every other similarly situated non-net-metering customer. Far from being discriminatory, Rider NMS-2 is a proposal to treat future customer-generators in exactly the same way as all other similarly situated non-customer-generators. With Rider NMS-2, the Companies are seeking to protect all customers and fulfill their obligation to provide lowest reasonable cost service by ensuring that they do not overpay customer-generators, *as* generators, for the energy that they supply onto the grid.

Q. In what position does a customer-generator *as* generator stand in relation to the Companies?

A. A customer-generator *as* generator stands in the position of a supplier to the Companies, not a customer. The Companies alone have the right and obligation to serve customers in their respective certified electric service territories.[15] Therefore, customer-generators do not have a right to serve their neighbors at retail when they supply energy onto the Companies' system; rather, when customer-generators produce energy onto the Companies' system, they are suppliers to the Companies at wholesale, not suppliers to their neighbors at retail. This negates entirely any notion that Rider

[15] *See* KRS 278.017 and 278.018.

NMS-2 customers should be compensated at retail rates.[16] Indeed, the Companies must ensure they do not overpay suppliers, or they risk having such overpayments deemed to be imprudent by the Commission and therefore unrecoverable through rates.

Q. Do Kentucky's Net Metering Statutes put customer-generators in a different position from other suppliers to the Companies?

A. Yes, but only to a limited extent. Unlike most other suppliers (but like qualifying facilities, "QFs"), customer-generators have a right to require utilities to purchase their output without a contract or commitment.[17] Also unlike most other suppliers, the Companies cannot negotiate terms, including the compensation rate for energy supplied; rather, KRS 278.466(3) requires that the Commission set the compensation rate for customer-generators "using the ratemaking processes under this chapter during a proceeding initiated by a retail electric supplier …."

But that is the full extent of additional rights afforded customer-generators as suppliers to the Companies. Notably, nothing in KRS Chapter 278 requires a utility to pay a customer-generator more for its output than it would pay any other similarly situated generator who was not a customer-generator. Stated differently, everything in KRS Chapter 278 requires that customers pay rates that include only prudently incurred costs that contribute to lowest reasonable cost service; there is no exception to that standard for purchases from customer-generators.

Q. Do Kentucky's Net Metering Statutes entitle net metering customers to a particular return on their investments in generating equipment?

[16] KRS 278.017 and 278.018.

[17] KRS 278.466(3) and (6).

A. No. Contrary to Mr. Rábago's assertions, net metering customers are not entitled to any return on their investments in generating equipment,[18] and there is nothing "punitive" or "confiscatory" about the proposed Rider NMS-2.[19] It is important to recognize the fundamental distinction between utility investments and customer-generators' investments. In Kentucky, electric utilities like the Companies have both an exclusive right and an obligation to serve customers in their certified service territories. They cannot build or acquire most generating facilities to serve their customers without obtaining Commission approval, and they cannot recover the costs of their investments through rates without Commission approval. If the Commission deems a utility investment to be imprudent, the utility cannot recover the cost of that investment through rates.

In contrast, customer-generators have no obligation to serve anyone, including themselves. They can make whatever generation investments they like (consistent with law) at whatever costs they like, without the Commission's approval and without any outside prudence review. It is entirely their decision how much of an investment in generation to make or whether to make any such investment at all. And though I am not a lawyer, I am not aware of any legal requirement that net metering customers are entitled to any return of or on the investments they freely choose to make. In other words, it is up to net metering customers to decide whether they believe it is worth investing in generating assets; they are under no obligation to do so, and nobody will second-guess their choices.

[18] *See* Rábago Testimony at 22-24.
[19] Rábago Testimony at 23.

And it is important to reiterate that the Companies are not proposing to change the compensation arrangements under which ***current*** net metering customers operate; indeed, KRS 278.466(6) precludes the Companies from doing so. The only question is whether ***future*** net metering customers will continue to receive the same excessive compensation that current net metering customers receive—at other customers' expense—for the as-available, non-firm energy they produce onto the Companies' grid. In other words, the only people whose investments will be affected by Rider NMS-2 are people who have not yet made those investments and will have the chance to decide whether they believe such investments are worth making under the Rider NMS-2 regime. Therefore, there is absolutely no sense in which Rider NMS-2 is "confiscatory" or "punitive."

A related point that Mr. Rábago makes is that Rider NMS-2 as proposed would slow the rate of net metering growth and therefore should be rejected.[20] This too is a point that finds no support in Kentucky's Net Metering Statutes. The General Assembly has established a firm, permanent ceiling on the amount of net metering a utility must offer; it has not established a minimum amount of net metering a utility must have or stated a policy advocating for the growth and development of net metering.[21] Therefore, whatever the effect of Rider NMS-2 might be on the growth of net metering, it is irrelevant to considering the appropriate compensation rate for Rider NMS-2, which more than 99% of other customers will pay for the energy NMS-2 customers intermittently supply to the grid.

[20] *See, e.g.,* Rábago Testimony at 22-23 and 31-32.
[21] *See* KRS 278.466(1).

Finally, I would note that the Kentucky Supreme Court has stated, "Utility ratepayers have no vested property interest in the rates they must pay for a utility service despite the fact that it is provided by a regulated monopoly."[22] Even current net metering customers have no such right: if the Companies' rates or rate structures applicable to their rate classes change, then their rates or rate structures change, too, regardless of whether that affects the return of or on their generating investments. Therefore, Mr. Rábago's assertions that Rider NMS-2 would deprive net metering customers of a return on investment to which they are entitled, or that Rider NMS-2 is somehow "confiscatory," are entirely unfounded.

Q. Does KRS 278.466(3) create a new standard for compensation paid to customer-generators?

A. No. I am not a lawyer, but the text of KRS 278.466(3) seems clear: "The rate to be used for such compensation shall be set by the commission using the ratemaking ***processes*** under this chapter during a proceeding initiated by a retail electric supplier …" (emphasis added). The text concerns processes, not standards; a process is not a standard. In other words, the statute prescribes *how* to set compensation for net metering customers, not *what* the compensation should be or the standards to apply in setting it. In other words, the Commission should evaluate compensation paid to customer-generators in exactly the same way in which the Commission would evaluate the prudence of compensation paid to any other generator that supplies energy to the Companies for serving their retail customers.

[22] *KIUC v. KU*, 983 S.W.2d 493, 497 (Ky. 1998).

The standard that clearly does apply to energy acquisition by utilities is lowest reasonable cost, a standard the Commission has reiterated time and again for decades. For example, the Commission has firmly declared that it "is responsible for ensuring that utilities provide safe and reliable electric service at the least cost."[23] It has directed all electric generation utilities to develop on a regular ongoing basis a "resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost."[24] Kentucky's highest court has noted that one of the Commission's most important objectives is "providing the lowest possible cost to the ratepayers."[25] And in an order in a KU rate case nearly 30 years ago, the Commission stated its "belief that it has an obligation to pursue, for Kentuckians, an energy strategy that represents least cost consistent with appropriate reliability …."[26] In short, the standard that has always applied to utilities' energy acquisitions is lowest reasonable cost consistent with safe and reliable operations. KRS 278.466(3) does not articulate or require the application of another standard.

The Commission recently reiterated that standard in its final order in Case No. 2020-00016, which concerned a 20-year power purchase agreement ("Solar PPA") under which the Companies will receive all of the output of a 100 MW solar facility to

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[23] *Application of Kentucky Power Company For: (1) A General Adjustment of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; and (4) An Order Granting All Other Required Approvals and Relief*, Case No. 2014-00396, Order at 34 (Ky. PSC Jun. 22, 2015).

[24] 807 KAR 5:058 Section 8(1) (requiring all electric generation utilities to develop a "resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost.").

[25] *Public Service Commission v. Continental Telephone Company*, 692 S.W.2d 794, 799 (Ky. 1985).

[26] *General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 8624, Order at 54 (Ky. PSC Mar. 18, 1983).

be built in Kentucky at a flat rate for the entire 20-year term of less than $28/MWh ($0.028/kWh).[27] (A copy of the Solar PPA is attached to my testimony as Rebuttal Exhibit RMC-1.[28]) In that order, the Commission—quoting the Kentucky Supreme Court—stated, "[O]ne of the Commission's 'most important roles' in administering KRS Chapter 278, 'is to provide the lowest possible cost to the rate payer.'"[29] Nothing about the revised KRS 278.465 or 278.466 changes that role for the Commission; rather, the General Assembly has now empowered the Commission to ensure it can help "provide the lowest possible cost to the rate payer" by approving compensation rates for customer-generators that do not overpay them at other customers' expense.

Q. Is there a similar service to which you believe the Commission should compare the Companies' proposed compensation rate under Rider NMS-2?

A. Yes. There is no fundamental distinction between the service the Companies receive from customer-generators and the service the Companies receive from small qualifying facilities ("SQFs") providing power on an as-available basis after serving their own needs first. In both cases there is no contract, no obligation for the generator to provide any particular amount of energy at any time, and indeed no obligation even for the generator to be kept in operation. Instead, customer-generators simply produce energy

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[27] *Electronic Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source under Green Tariff Option #3*, Case No. 2020-00016, Order (PSC Ky. Dec. 16, 2020); Case No. 2020-00016, Order (PSC Ky. May 8, 2020).

[28] Note that Rebuttal Exhibit RMC-1 has certain redactions that are not relevant to these proceedings. The Commission granted confidential protection for the redacted information in Case No. 2020-00016. *See* Case No, 2020-00016, Order (PSC Ky. May 8, 2020).

[29] Case No. 2020-00016, Order at 7 (PSC Ky. Dec. 16, 2020), *quoting Public Service Comm'n v. Dewitt Water District*, 720 S.W.2d 725, 730 (Ky. 1986) ("The Commission has ignored one of its most important roles, which is to provide the lowest possible cost to the rate payer.").

onto the Companies' system as and when they can, and the Companies must purchase the energy regardless of need. Such energy is as-available, non-firm energy.

According to the Commission's QF regulation, "Rates for power offered on an 'as available' basis shall be based on the purchasing utility's avoided energy costs estimated at time of delivery."[30] The Commission recently accepted the appropriate rates for such purchases by the Companies, which are in the Companies' Rider SQF.[31] It is the same rate the Companies are proposing to use to compensate Rider NMS-2 customers, who provide exactly the same service under exactly the same terms as SQF customers. There is no sound logical argument for treating them differently. Therefore, the non-time-differentiated SQF rate is the correct rate to use to compensate Rider NMS-2 customers for energy produced onto the grid.

Q. Is the Solar PPA another appropriate comparison for the Companies' proposed Rider NMS-2 compensation?

A. Yes. Under the Solar PPA, there are no demand charges or other compensation the Companies will pay for the energy they receive. The Solar PPA includes performance guarantees with liquidated damages,[32] and it provides to the Companies all of the renewable energy certificates ("RECs") created by the facility.[33] The output of 75 MW of the facility will serve, and the associated RECs will be provided to, two large customers under the Companies' Green Tariff Option #3.[34] The output of the

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[30] 807 KAR 5:054 Section (7)(2)(a).
[31] Kentucky Utilities Company, P.S.C. No. 19, First Revision of Original Sheet No. 55 (accepted for filing June 30, 2020); Louisville Gas and Electric Company, P.S.C. Electric No. 12, First Revision of Original Sheet No. 55 (accepted for filing June 30, 2020).
[32] Rebuttal Exh. RMC-1 at 32-33.
[33] *Id.* at 29.
[34] Case No. 2020-00016, Application at 9 (Jan. 23, 2020).

remaining 25 MW will serve all of the Companies' customers, and the Companies plan to sell the related RECs to help offset the cost of the energy.[35]

All of this compares very favorably to what the Companies—and therefore their customers—receive from customer-generators. Whereas the Solar PPA provides a 20-year commitment, customer-generators provide no commitment at all. Whereas the Solar PPA provides performance guarantees with liquidated damages, customer-generators have no obligation to perform or even to continue to exist. Whereas the Solar PPA provides RECs to the Companies and their customers, customer-generators keep for themselves whatever marketable renewable power attributes they can create. And whereas the output of the Solar PPA facility is available to serve all of the Companies' customers, each customer-generator's output serves the customer-generator first, leaving only the excess energy, if any, to be provided to the Companies to serve other customers, which is a customer preference unique to that kind of generation that increases the intermittency and unreliability of such generation for utility planning purposes.

In other words, the Companies and their customers receive far more under the Solar PPA than they receive from any customer-generator.

Yet the Companies and their customers receive all of the benefits of the Solar PPA for \$0.02782/kWh, not counting offsetting revenues from REC sales. Notably, RECs have traded in the Ohio market between \$5 and \$12 per REC in the last 12 months, i.e., between \$0.005/kWh and \$0.012/kWh.[36] The Companies have been able

[35] Case No. 2020-00016, Direct Testimony of David S. Sinclair at 15 (Jan. 23, 2020).
[36] *See* https://www.srectrade.com/markets/rps/srec/ohio (accessed Mar. 17, 2021), archived on Mar. 17, 2021, at https://web.archive.org/web/20210317175011/https://www.srectrade.com/markets/rps/srec/ohio.

to sell RECs created from the output of the Brown Solar Facility over that same period for prices ranging from \$8.25/REC to \$11.00/REC, i.e., \$0.00825/kWh to \$0.011/kWh. Over the last three years, the Companies have averaged \$8.78/REC from Brown Solar, which is \$0.00878/kWh. Applying the Brown Solar three-year average REC revenue to the Solar PPA's pricing would result in a net cost of Solar PPA energy of \$0.01904/kWh. Although REC prices will continue to vary, this is evidence that, compared to the pricing and value of the Solar PPA, compensating Rider NMS-2 customers at a rate of \$0.02173/kWh is likely overpaying for what the Companies and their customers receive: no commitment, no availability guarantees, no fixed pricing, and greater intermittency due to customer-generators' own first call on the energy they produce. Arguably, \$0.02173/kWh is the ***most*** net metering customers should receive from the Companies' other customers under current market conditions; certainly there is no justification for paying more than that. Indeed, the Companies could reasonably expect to be criticized by the Commission, the Attorney General, and others for purchasing energy at prices greater than market value.

Q. What did the Commission's orders state concerning demand credits related to, and the capacity value of, the Solar PPA?

A. The Companies had proposed renewable power agreements that would have treated the energy from the Solar PPA largely as being behind the meter for the two customers served by 75 MW of the Solar PPA facility's output. More precisely, the customers would have paid the Companies for the energy produced at the Solar PPA rate, not the Companies' retail rates, and would have received intermediate and peak, but not base, demand offsets that aligned with the production of the Solar PPA facility.[37] The Commission rejected demand offsets of any kind, calling such offsets "a subsidy":

> Toyota and Dow will receive a subsidy because nonfirm energy produced by the solar facility offsets Toyota's and Dow's demand, resulting in a shift in cost recovery of fixed assets in subsequent rate proceedings from Toyota and Dow to LG&E/KU's nonparticipating customers.[38]

On the Commission's reasoning, "nonfirm energy," which is exactly what customer-generators produce, cannot create demand benefits. Therefore, contrary to certain intervenors positions,[39] customer-generators cannot be compensated for supposed demand benefits, long-term or otherwise, according to the logic of the Commission's own orders. Furthermore, customer-generators are avoiding paying fixed costs that are embedded in the energy rate for any consumption, as a customer, that is being offset from the customer-generators generation facility. This results in shifting cost recovery of fixed assets to other customers in future rate proceedings.

Regarding capacity provided by the Solar PPA, the Commission stated in another order in that proceeding, "As a non-firm energy-only purchase agreement, the PPA cannot be relied upon for generating capacity used to meet the statutory requirement that electric utilities provide adequate, efficient and reasonable service."[40] That exact same proposition applies to net metering customers, only more so: unlike the Solar PPA, customer-generators provide no availability guarantees or any other legally enforceable obligation. Moreover, customer-generators' energy production to

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[37] Case No. 2020-00016, Application Exhs. 2 and 3 (Jan. 23, 2020).
[38] Case No. 2020-00016, Order at 6-7 (June 18, 2020).
[39] *See, e.g.,* Inskeep Testimony at 15; Rábago at 11.
[40] Case No. 2020-00016, Order at 7 (Dec. 16, 2020).

the Companies' grid is necessarily less valuable for the purpose of serving all customers because customer-generators' loads have first call on their production. Therefore, there simply is no capacity value provided by net metering, and net metering compensation rates should not include a capacity value component.

Q. Mr. Rábago has argued that some kind of Value of Solar should factor into compensation for net metering customers.[41] What value, if any, do customer-generators provide that the Solar PPA, Brown Solar, or the Companies' Solar Share Facilities do not?

A. Little, if any. To understand this, it is helpful to categorize the solar benefits claimed by Mr. Rábago and certain other intervenor witnesses into three categories:

1. Short-term avoided cost benefits (e.g., avoided production costs, line losses, hedging benefits). The most plausible benefit net metering customers could provide in this regard that the Companies' other renewable resources could not involves avoided line losses, though the intervenors have not quantified this claimed benefit; Mr. Seelye addresses claimed line losses and hedging benefits in his rebuttal testimony. Notably, QFs could provide all the same benefits as customer-generators, making SQF compensation for Rider NMS-2 customers appropriate.

2. Long-term avoided cost benefits (e.g., claimed generation, transmission, and distribution savings). There is no reason to believe that as-available, non-firm energy can provide any of these benefits, as the Commission itself has recently stated and the Commission's current QF regulations recognize.[42] In addition,

[41] *See, e.g.,* Rábago at 6 and 40-41.
[42] Case No. 2020-00016, Order at 6-7 (June 18, 2020); 807 KAR 5:054 Section (7)(2)(a).

there is no basis in Kentucky's Net Metering Statutes for compensating these alleged capacity-based benefits.[43]

3. Externalities (e.g., environmental and health benefits). The Companies' current solar and hydro resources provide all of the same benefits that fall in this category. The Companies neither compensate others nor receive compensation from customers for these alleged benefits, which the Commission has stated are outside its jurisdiction to consider or to require utilities to consider: "The Commission has no jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or service. Lacking jurisdiction over these non-energy factors, the Commission has no authority to require a utility to include such factors in benefit-cost analyses of DSM programs."[44] There is no reason to treat net metering customers differently. Indeed, if net metering customers are to be compensated for the extrinsic benefits of solar, it would be logical for the Companies to be similarly compensated.[45] Of course, the Companies are not advocating for such compensation, but are merely laying bare the logical entailments of certain intervenors' arguments.

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[43] Companies' Response to PSC-4 Strategen No. 4.

[44] *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441, Order at 28 (Ky. PSC Oct. 5, 2018). *See also The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2011-00140, Order at 4 (Ky. PSC July 8, 2011) ("[I]ssues of environmental externalities, such as air and water pollution from generating electricity and mining fuel to supply the generating plants, are all issues beyond the scope of the Commission's jurisdiction.").

[45] Notably, when the Companies asked the Joint Intervenors whether the Commission should permit the Companies to collect from customers the Value of Solar in excess of the Companies' costs, Mr. Rábago responded only that Kentucky has cost-of-service-based ratemaking. (Joint Intervenors' Response to Companies' DR 1-16.) The Companies agree, but Mr. Rábago's response proves the Companies' point: the "Value of Solar" consists largely of extrinsic items that play no part in costs to serve customers and are outside the Commission's jurisdiction. Moreover, neither Mr. Rábago nor any other intervenor has attempted to quantify the "Value of Solar" for the Companies, so it would be impossible to compensate customer-generators or the Companies for such a value. (*See, e.g.*, Joint Intervenors' Response to Companies' DR 1-17.)

B. <u>Customers, Not the Companies and Their Shareholders, Ultimately Pay the Cost of Compensating Customer-Generators</u>

Q. Who ultimately pays the Rider NMS-2 compensation rate the Commission prescribes?

A. The Companies' customers, not the Companies' shareholders, will pay the rate the Commission prescribes. The Companies will collect the cost of the energy the Companies purchase from Rider NMS-2 customers through their Fuel Adjustment Clauses. So the decision before the Commission is not what the Companies will pay, but rather what other customers will pay for the as-available, non-firm energy provided by customer-generators. The Companies believe the correct amount is the avoided production cost of the energy the Companies do not have to produce due to the energy provided by customer-generators. There simply is no reason to require other customers to pay customer-generators in their role as suppliers more than the Companies would prudently pay to any other similarly situated supplier providing the same service under the same terms.

Q. What has Attorney General witness Stephen J. Baron said regarding the Companies' proposed Rider NMS-2 compensation?

A. Mr. Baron stated in his direct testimony in these proceedings, "The current rate that the Companies are paying for net, exported excess solar generation pursuant to Rider NMS-1 is too high and results in subsidies of net metering customers by non-participating customers. The Companies' proposed Rider NMS-2 provides a reasonable rate for exported excess solar generation."[46] Of course, the Companies and the Attorney General do not agree on every issue in these proceedings, but it is noteworthy

[46] Baron Testimony at 7.

that the party tasked with representing all customers—both customer-generators and non-customer-generators—is supporting the Companies' proposed Rider NMS-2 as a reasonable means of compensating new net metering customers.[47] Also, presumably the Attorney General, who is Kentucky's chief law enforcement officer, would not support the Companies' Rider NMS-2 proposal if he believed it to be inconsistent with Kentucky's Net Metering Statutes.

C. There Is No Rational Basis for Providing Legacy Rights to New Net Metering Customers

Q. Mr. Inskeep advocates for "legacy rights" for new net metering customers.[48] Is there a rational basis for such rights?

A. No. By definition, legacy rights or status would apply only to a customer that had taken service and had legitimate expectations that rates, terms, or conditions would continue unchanged indefinitely into the future. No such rights or status could logically attach to a customer who had not yet begun to take the service for which the legacy rights or status is claimed. Yet Mr. Inskeep suggests that new net metering customers, i.e., those who begin taking service under Rider NMS-2 on or after the date on which new rates take effect from these proceedings, should have 25-year legacy rights to the compensation rate and other terms and conditions in place on the day on which a new net metering customer begins taking service under Rider NMS-2. Whatever such a pre-investment guarantee of unchanging compensation, terms, and conditions is, it is not "legacy."

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[47] *See* KRS 367.150(8)(b).
[48] *See* Inskeep Testimony at 37-48.

Of course, Mr. Inskeep is not suggesting that Rider NMS-2 customers assume any obligation to obtain these "legacy" rights. Instead, he proposes the Companies—and their customers—assume a unilateral 25-year obligation, which new net metering customers could individually impose at times solely of their choosing, without Commission approval, and without any obligation at all on the part of the customer-generators: no obligation to provide energy at any time; no obligation to have capacity functioning or available, and certainly no liquidated damages or other financial consequence for not having capacity functional or available; indeed, no obligation to continue to own or operate generating facilities at all.

The true legacy rights concerning net metering belong to existing net metering customers who are taking service under Rider NMS-1. The General Assembly provided those rights when it revised Kentucky's Net Metering Statutes.[49] Had the General Assembly intended to provide additional rights of the kind Mr. Inskeep desires, it could have done so when it fundamentally changed how net metering works in Kentucky. But the General Assembly did not provide what Mr. Inskeep wants, so he is asking the Commission to invent rights not found in the recently revised statute. I respectfully suggest that, as a creature of statute, the Commission should refuse Mr. Inskeep's invitation to create 25-year property rights in rates that the General Assembly did not create and that the Kentucky Supreme Court has previously stated customers do not have.[50]

[49] KRS 278.466(6).
[50] *KIUC v. KU*, 983 S.W.2d 493, 497 (Ky. 1998) ("Utility ratepayers have no vested property interest in the rates they must pay for a utility service despite the fact that it is provided by a regulated monopoly.").

D. Response to Mr. Rábago's Comments in Case No. 2019-00256

Q. Do you have any response to the comments Mr. Rábago filed in Case No. 2019-00256, to which Mr. Rábago referred in his direct testimony in these proceedings?[51]

A. Yes. Most of the issues Mr. Rábago raised in his comments in Case No. 2019-00256 are addressed elsewhere in my and Mr. Seelye's rebuttal testimony. But there is an issue he raised in that proceeding that merit response here.

Mr. Rábago stated in his comments, "The subject matter at issue here is nothing more than the right of all of Kentucky's citizens to participate in the self-generation marketplace and to become at least in part free of monopoly domination over their electricity service needs and bills."[52] This is simply untrue. Net metering does not aid customers to gain independence from their serving utilities; rather, net metering permits participating customers to self-supply part or all of their energy needs when their generators are producing energy. But they depend on their serving utilities 100% of the time to provide every single kWh they do not produce. Given the intermittency of renewable generation, net metering customers need their utility to be ready to serve at any and every moment.

Truly to become independent from a serving utility would require a customer-generator to disconnect entirely from utility service and self-provide the customer's energy needs. Realistically, very few people are prepared or financially able to build

[51] *See* Revised Direct Testimony of Karl R. Rábago at 5 n.5, incorporating by reference *Electronic Consideration of the Implementation of the Net Metering Act*, Case No. 2019-00256, Public Comments of Karl R. Rábago ("Rábago Comments") (PSC Ky. Nov. 13, 2019).
[52] Rábago Comments at 1.

their own generation and energy storage sufficient to meet their own energy needs—and to accept the reliability trade-off associated with disconnecting from the grid.

Moreover, the Companies do not oppose and are not proposing to constrict in any way "the right … of Kentucky's citizens to participate in the self-generation marketplace." The Companies neither could nor would seek to interfere with customers' statutory rights to self-generate provided under Kentucky's Net Metering Laws.

Contrary to what Mr. Rábago suggests was at issue in Case No. 2019-00256, what is actually at stake in these proceedings concerning net metering is what the more than 99% of customers who are not net metering customers must pay future customer-generators for the as-available, non-firm energy they supply onto the Companies' system. Although that does not sound as consequential or dramatic as what Mr. Rábago suggests was at issue in Case No. 2019-00256, it is what is actually at issue regarding net metering in these proceedings. The Companies' position is that more than 99% of customers should not be forced to pay more than avoided production cost for the energy that future customer-generators produce onto the Companies' system.

III. CONCERNS REGARDING INCREASING RESIDENTIAL BASIC SERVICE CHARGES

Q. Ms. Kuhn asserts that increasing the Companies' residential Basic Service Charges will "act[] as a disincentive for customers to implement energy efficiency practices in their homes."[53] How do you respond?

A. Mr. Seelye addresses this issue at length in his direct and rebuttal testimony, but I can succinctly address this concern.

[53] Direct Testimony of Cathy Kuhn ("Kuhn Testimony") at 9.

KU has proposed an average residential customer bill increase of $12.85,[54] of which less than $2.45 results from an increased Basic Service Charge.[55] The remaining increase of more than $10.00 per month results from increased energy charges and other usage-driven charges.

The same is true for LG&E electric, which has proposed an average residential customer bill increase of $11.74,[56] of which less than $2.15 results from an increased Basic Service Charge.[57] The remaining increase of more than $9.50 per month results from increased energy charges and other usage-driven charges.

The same is also true for LG&E gas, which has proposed an average residential customer bill increase of $6.17,[58] of which less than $4.00 results from an increased Basic Service Charge.[59] The remaining increase of more than $2.00 per month results from increased commodity charges and other usage-driven charges.

Therefore, it is incorrect to assert that granting the Companies their requested residential Basic Service Charges will decrease incentives to engage in energy efficiency or conservation. Under the Companies' requested rates, all customers will have an increased, not a decreased, incentive to engage in energy efficiency, all consistent with moving residential Basic Service Charges closer to cost of service.

Examined from another perspective, assume the Commission approved the Companies' proposed residential revenue increase but required the current Basic

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[54] KU Application Sch. M-2.2.
[55] *See* KU Application Sch. M-2.3. Multiplying the $0.08 difference between the current daily charge of $0.53 and the proposed charge of $0.63 by 365 days and dividing by 12 months yields $2.43.
[56] LG&E Application Sch. M-2.2-E.
[57] *See* KU Application Sch. M-2.3-E. Multiplying the $0.07 difference between the current daily charge of $0.45 and the proposed charge of $0.52 by 365 days and dividing by 12 months yields $2.13.
[58] LG&E Application Sch. M-2.2-G.
[59] *See* KU Application Sch. M-2.3-G. Multiplying the $0.13 difference between the current daily charge of $0.65 and the proposed charge of $0.78 by 365 days and dividing by 12 months yields $3.95.

Service Charges to remain unchanged. Assume further a customer with average usage were able to reduce energy use by 10%, which would be a significant reduction for many customers. The additional monthly savings resulting from not increasing the Basic Service Charge for such a customer would be about $0.25 for a KU customer, $0.22 for an LG&E electric customer, and $0.40 for an LG&E gas customer. It is implausible to suggest that a customer's decision whether to undertake an energy efficiency effort would turn on such small differences in monthly savings. Thus, increasing the Companies' residential Basic Service Charges as proposed would be consistent with cost of service and would increase energy efficiency incentives relative to today's rates, and would not materially reduce such incentives relative to keeping the Basic Service Charges at present levels.

Q. Ms. Kuhn asserts that because low-income customers tend to use less energy than higher-income customers, increasing residential Basic Service Charges causes low-income customers to subsidize higher income customers.[60] Is she correct?

A. No. As Mr. Seelye explained in his direct testimony, the Companies' proposed Basic Service Charges are based on costs that do not change with usage.[61] Moving residential Basic Service Charges closer to cost of service therefore more accurately collects costs that do not vary with usage through charges that do not vary with usage. This does not increase intraclass subsidies, but rather reduces them.

Also, increasing the Companies' residential Basic Service Charges actually helps some low-income customers, namely those who receive third-party assistance,

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[60] Kuhn Testimony at 8.
[61] Direct Testimony of William Steven Seelye at 16-21.

who have above-average energy consumption.[62] Customers who receive such assistance are those most in need, and they tend to have above-average usage, which is why recovering fixed costs through fixed charges is particularly helpful to them.

Q. Do you agree with Ms. Kuhn that low income areas tend to be dense and have more meters in a given area, making those areas lower cost to serve and resulting in subsidies from those areas to higher income areas that an increased residential Basic Service Charge will exacerbate?[63]

A. No. Some of the lowest income areas the Companies serve are in KU's service territory, and those tend to be less densely populated than some higher-income areas the Companies serve.

Moreover, as the Companies noted in their discovery responses on this topic, the cost of distribution facilities in dense neighborhoods is often higher because the facilities often utilize underground distribution facilities in dense neighborhoods, which are often more costly to install.[64] The expense numbers Ms. Kuhn cites to assert that above-ground, overhead distribution facilities are more costly than underground facilities are totals, not costs per circuit mile.[65] The Companies have vastly more overhead distribution circuit miles than underground circuit miles, so it is inaccurate to look at total annual cost figures for a single year and infer that one system is more expensive than another on a per-customer basis.[66] Allocating the costs cited by Ms. Kuhn solely on a circuit-mile basis shows that overhead facilities have lower expenses

[62] *See, e.g.,* KU Response to PSC 2-135; LG&E Response to PSC 2-155.
[63] Kuhn Testimony at 8-9.
[64] Companies' Response to MHC et al. DR No. 1-51.
[65] Companies' Response to MHC et al. DR No. 2-4.
[66] *See* Wolfe Direct Exh. JKW-1 at 4 ("Circuit miles – 23,000 (Overhead – 77%, Underground – 23%)").

per circuit mile in the test year than do underground facilities.[67] Therefore, the data Ms. Kuhn cites does not support her assertion.

IV. CONCERNS REGARDING LOW- AND FIXED INCOME CUSTOMERS

Q. Do you have any comments regarding the intervenor testimony concerning the challenges that low- and fixed-income customers face?[68]

A. Yes. First, the Companies understand that low- and fixed-income customers face financial difficulties that other customers do not, including the higher burden that utility bills are to such customers as a percentage of their incomes.[69] That is why, as Eileen L. Saunders discussed at length in her direct testimony, the Companies do their best to provide assistance, including significant shareholder-funded assistance, to low- and fixed-income customers.[70] Regarding shareholder contributions, the Companies have committed to provide at least $1.45 million annually through June 30, 2021, to support low-income programs, all of which is in addition to shareholder funds contributed to the WinterCare and WinterHelp programs. These contributions are in addition to funds contributed by other customers to those programs. The Companies also provide the WeCare DSM-EE program, late-payment charge forgiveness for customers receiving authorized agency assistance, and the FLEX Program to extend bill payment deadlines for customers with fixed incomes. The Companies also collect HEA charges of $0.30 per month that go to help customers in need. In addition, the Companies have for years had strong partnerships and trusting working relationships with low-income assistance

[67] The Companies do not necessarily advocate this approach as the most accurate way to allocate such costs, but it is sufficient to demonstrate the fallacy of reviewing total cost numbers and asserting which system is more costly on a per-customer basis.
[68] Kuhn Testimony at 4-9; Direct Testimony of James Owen ("Owen Testimony") at 7-28.
[69] *See* Companies' Response to PSC 3-28 Attachment 1 at 4.
[70] Direct Testimony of Eileen L. Saunders at 12-18.

groups. In sum, the Companies take low-income issues seriously and have done so for years.

Moreover, the Companies recognize the difficulties COVID has created for all customers, especially low- and fixed-income customers. That is why the Companies are proposing their Economic Relief Surcredit Adjustment Clauses, which will provide total surcredits of $11.9 million to KU customers, $38.9 million to LG&E electric customers, and $2.7 million to LG&E gas customers, all in the first year the Companies' proposed rates will take effect.[71] These surcredits will help make the rate increases resulting from these proceedings more affordable while Kentucky's economy recovers from COVID.

But it is also important to recognize the constraints that exist concerning rates for low- and fixed-income customers. The Commission has long held that low-income rates are not permissible;[72] it has never deviated from that position, which is consistent with the requirement of KRS 278.170(1) not to discriminate with regard to rates or service for "doing a like and contemporaneous service under the same or substantially the same conditions." Moreover, the Commission has stated that it cannot consider affordability in determining the reasonableness of rates: "[A]ffordability is not a factor that the Commission can consider because KRS 278.170(1) prohibits rates that establish an unreasonable preference between classes of service for doing a like service under the same or substantially the same conditions."[73] Therefore, although the

[71] *See, e.g.,* Direct Testimony of Robert M. Conroy at 5.
[72] *See, e.g., Application for Adjustment of the Rates of Kentucky-American Water Company*, Case No. 2004-00103, Order at 82-84 (Ky. PSC Feb. 28, 2005).
[73] *Electronic Application of Kentucky-American Water Company for Adjustment of Rates*, Case No. 2018-00358, Order at 3 (Ky. PSC Jan. 3, 2019).

information the intervenors have provided regarding the difficulties low- and fixed-income customers face is sobering, there are limits to how that information can bear upon ratemaking under current statutes.

Q. Certain intervenor witnesses have asserted that the Companies' proposed rate increases are effectively racially discriminatory.[74] How do you respond?

A. The Companies take these assertions seriously because they are committed to diversity. In addition, the Companies, as they both desire to do and are required to do under KRS 278.170, provide service on a non-discriminatory basis, without any regard for their customers' race, color, ethnicity, national origin, sexual orientation, or any other such characteristic or trait. The Companies are grateful to serve diverse communities with a diverse workforce.

Q. Will the Companies' proposed AMI deployment unduly burden low-income customers as Ms. Kuhn alleges?[75]

A. No. The Companies' proposed rates in these proceedings contain no cost recovery for the proposed AMI deployment. Moreover, the Companies have committed not to have AMI deployment costs included in base rates prior to the completion of the deployment so all customers will begin receiving AMI benefits before any AMI costs are included in base rates.[76] And the Companies' proposed ratemaking approach helps to avoid any increase in the combined revenue requirements of the Companies over the analysis period.[77] It is the Companies' goal that customers would not see an increase in revenue

[74] Kuhn Testimony at 5-8; Owen Testimony at 17-19.
[75] Kuhn Testimony at 9-10.
[76] *See, e.g.,* Direct Testimony of Kent W. Blake at 9-20.
[77] *See, e.g.,* LG&E Response to DOD-FEA DR 2-28; KU Response to DOD-FEA DR 2-28.

requirement associated with the AMI deployment and would at least have the opportunity to experience benefits.

Some benefits that will be available to all customers may be particularly appealing to low- and fixed-income customers. These benefits include the availability of prepaid service and no disconnection-reconnection charges. In addition, many low- and fixed-income customers have smart phones or other access to the Internet, and therefore will be able to access their own usage data at a much more granular level than they can today. Customers may find that using that data will allow them to determine more precisely what devices and practices consume the most energy and make more informed and efficient energy consumption decisions. Low- and fixed-income customers might also choose to grant access to their data to others who could help them, such as low-income assistance agencies, even if such customers do not have the means to obtain or analyze the data on their own. Therefore, the Companies believe low- and fixed-income customers will receive benefits from, and will not be unduly burdened by, the proposed AMI deployment.

V. OTHER RATE AND TARIFF MATTERS

Q. Mr. Owen states that he was unable to calculate the residential bill impacts the Companies included in their notices in these proceedings, and his calculations showed a higher bill impact for KU, LG&E electric, and LG&E gas.[78] Are the Companies' calculated bill impacts correct?

A. The Companies' residential bill impact calculations were correct and based on the impact to the total bill, inclusive of base rates and all adjustment clause mechanisms.

[78] Owen Testimony at 7-8; Joint Intervenors' Response to Companies' DR 1-1, Owen Workpaper_1.xlsx.

Mr. Owen calculated bill impacts by beginning with the current and proposed residential Basic Service Charges and adding the current and proposed energy rates times the average residential usage for each utility.[79] He treated the results of these calculations as the current and proposed average customer bill, and he then subtracted the two to obtain the monthly bill impacts: $13.49 for KU, $12.89 for LG&E electric, and $10.23 for LG&E gas.[80] Thus, his bill impact includes only the two base rate components: the Basic Service Charge and the energy charge.

The problem with Mr. Owen's bill-impact methodology is that it ignores the impacts of all cost-recovery mechanisms on the bill and changes in the costs recovered through the mechanisms. In other words, his methodology calculates a Basic Service Charge plus energy charge impact, not a bill impact. His methodology does not take into consideration the Companies' proposed ECR project eliminations and LG&E's proposed GLT project eliminations, all of which reduce mechanism-based cost recovery and increase recovery through base rates with no net impact to the total bill. The Companies' proposals were addressed in the same published notices that included the bill impacts Mr. Owen cites,[81] as well as the Companies' applications,[82] testimony,[83] and filing requirements.[84]

The Companies provided all of the relevant sources for the calculation of the published bill impacts, namely KU Schedules M-2.2 and M-2.3, LG&E Schedules M-

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[79] *Id.* at 8.
[80] *Id.* at 8.
[81] *Id.*
[82] Case No. 2020-00349, Application at 19; Case No. 2020-00350, Application at 20-21.
[83] *See, e.g.,* Conroy Direct at 15-16 and 55.
[84] KU Filing Requirements Tab 66 - 807 KAR 5:001 Section 16(8)(m), Schedules M-2.2 and M-2.3; KU Filing Requirements Tab 67 - 807 KAR 5:001 Section 16(8)(n), Schedule N; LG&E Tab 66 - 807 KAR 5:001 Section 16(8)(m), Schedules M-2.2-E and M-2.3-E and Schedules M-2.2-G and M-2.3-G; LG&E Filing Requirements Tab 67 - 807 KAR 5:001 Section 16(8)(n), Schedule N (electric) and Schedule N (gas).

2.2-E and M-2.3-E, and LG&E Schedules M-2.2-G and M-2.3-G, as well as Schedule N for each utility, which sets out each of the typical bill calculation components for various levels of consumption. All of these schedules were in the record of these proceedings more than three months before Mr. Owen filed his testimony. Similarly, the electronic spreadsheet versions of those schedules with formulas intact were in the record for two and a half months before Mr. Owen filed his testimony.[85] It is therefore odd that Mr. Owen was not aware of the ECR project eliminations at the time he filed his testimony.[86]

Q. Mr. Kollen's testimony addresses the Companies' Merger Mitigation Depancaking ("MMD") expenses, recommending that the Companies "defer all refunds and ongoing savings as regulatory liabilities for disposition in a future base rate or special proceeding" if the Companies succeed in reducing or eliminating MMD expenses.[87] What is the Companies' position on this issue?

A. It is important to bear in mind that the Companies continue to pay MMD transmission rates and have asked the Federal Energy Regulatory Commission ("FERC") for relief from those obligations for the benefit of their retail customers. Receiving a favorable FERC order—and when the issue might finally be resolved following a FERC order—is not at all certain.[88] It is therefore appropriate for the Companies' base rates to continue to include recovery of MMD costs, which are FERC-approved rates not subject to exclusion from the Companies' revenue requirements.

[85] Companies' Response to PSC 1-56.
[86] Joint Intervenors' Responses to the Companies' DR 1-2.
[87] Kollen Testimony at 100-103.
[88] *See* Companies' Response to AG-KIUC 1-59.

Nonetheless, the Companies agree with Mr. Kollen's recommendation. In fact, the establishment of deferral accounting for the MMD was part of the Addendum to Stipulation and Recommendation agreed to by all parties in the Companies' 2018 rate proceedings,[89] which the Commission approved in its final orders in those cases.[90] Deferral accounting is an appropriate means of addressing the possibility that FERC will reduce or eliminate the Companies' MMD obligations, and it would allow the Companies' retail customers to receive all of the benefits if the Companies succeed in their proceeding at FERC. Therefore, Mr. Kollen's recommended solution is already in place.

Q. Mr. Kollen proposes to eliminate the current sharing of off-system sales margins (75% to customers and 25% to the Companies) and recommends instead that 100% of such margins be provided to customers.[91] Do you agree with his proposed approach?

A. No, I do not agree with Mr. Kollen's proposal. The current 75%-25% sharing arrangement for off-system sales is highly favorable to customers and acts to encourage the Companies to aggressively seek opportunities to maximize off-system sales margins for customers.

In the Companies' 2014 rate cases,[92] the current sharing structure was negotiated among, and agreed to by, all parties, including the AG and KIUC, the parties on whose behalf Mr. Kollen is now testifying. The Commission agreed with the

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[89] See filing of Addendum to Stipulation and Recommendation on March 6, 2019 in Case Nos. 2018-00294 and 2018-00295.
[90] Case Nos. 2018-00294 and 2018-00295, Ordering paragraph 3 (Ky. PSC April 30, 2019).
[91] Kollen Testimony at 109-111.
[92] Case Nos. 2014-00371 and 2014-00372, Settlement Testimony of Kent W. Blake Exh. 1 (Settlement Agreement) (Ky. PSC Apr. 20, 2015).

settlement and approved it, thereby creating the Off-System Sales Adjustment Clause for each of the Companies, which entirely removed off-system sales margins from their base rates. Off-system sales margins are now addressed entirely through the Companies' respective Fuel Adjustment Clauses, which are not at issue in these proceedings.[93]

Moreover, Mr. Kollen is suggesting to fix something that is not broken. As the table below shows, since the inception of the Off-System Sales Adjustment Clause in July 2015, customers have received almost $22 million in total benefits:

$(000)	Customers	Companies	Total
2015	$1,051	$350	$1,401
2016	$2,097	$736	$2,833
2017	$2,076	$718	$2,794
2018[94]	$13,679	$4,770	$18,449
2019	$2,188	$747	$2,935
2020	$859	$297	$1,156
Total	$21,950	$7,618	$29,568

The results speak for themselves: the off-system sales sharing approach to which the AG and KIUC agreed is working for customers as intended, and there is no reason to change it.

Q. Mr. Kollen supports his proposal to allocate 100% of off-system sales margins to customers by asserting, "Customers are allocated 100% of the fixed costs, variable non-fuel expenses, and fuel expenses incurred to generate the energy that is sold off system to generate the OSS margins."[95] Is he correct?

[93] Case Nos. 2014-00371 and 2014-00372, Order (Ky. PSC June 30, 2015).
[94] The results for 2018 were extraordinary due to the polar vortex that occurred in January 2018. Because the Companies' generating assets were well maintained, they were available to meet customers' energy needs during extreme conditions and obtain financial benefits for customers through off-system sales.
[95] Kollen Testimony at 109-111.

A. No. Mr. Kollen is incorrect that customers are paying 100 percent of the fuel and non-fuel variable costs for off-system sales. As the Companies' monthly fuel adjustment clause filings clearly show, fuel and non-fuel variable costs for off-system sales are allocated between customers and the Companies on the same 75%-25% basis on which off-system sales margins are allocated. In other words, the fuel and non-fuel variable costs for off-system sales are covered by the revenues associated with making off-system sales, and customers and the Companies share in the margins on the agreed and approved 75%-25% basis.

In addition, Mr. Kollen does not recognize that the fixed costs included in the test year to establish base rates are being paid by customers only to the extent that future consumption mirrors the test-year level of consumption. The Companies bear the risk of native load sales volumes that can vary depending upon weather, economic conditions, and other factors that may lead to reduced sales volumes. Therefore, maintaining the current sharing arrangement is appropriate in part because it compensates the Companies for assuming these risks associated with the recovery of fixed costs.

Q. Mr. Kollen states that another rationale for the Commission to eliminate the current sharing of off-system sales margins is that it did so in the most recent Kentucky Power Company ("KPCo") rate case.[96] Do you agree with Mr. Kollen's logic?

A. No. Mr. Kollen is suggesting that the Companies and KPCo are similarly situated and thus should have a similar treatment for off-system sales. But from an off-system sales

[96] *Id* at 111.

perspective, the Companies and KPCo could not be more differently situated: KPCo is in the PJM RTO, and the Companies are not in an RTO. PJM is responsible for dispatching KPCo's generation and meeting its load. Thus, KPCo's off-system sales are simply an accounting exercise after-the-fact based on PJM's dispatch decisions.

In contradistinction, the Companies are responsible for dispatching their own units and finding and executing off-system sales transactions. The Companies' off-system sales transactions involve the MISO and PJM RTO markets, as well as direct transactions with utilities like TVA and energy marketers. In other words, the Companies have decisions to make about off-system sales that KPCo simply does not have to make. In the future, decisions will have to be made regarding possibly transacting on an hourly basis in MISO or PJM versus seeking to transact on SEEM. All of this requires personnel to make decisions about the best price opportunity, procure transmission, and assess the likely cost of generation. KPCo has to do none of this. Therefore, the Commission's decision regarding KPCo's off-system sales margins should have no bearing on the sharing of such margins to which the AG and KIUC previously agreed, which has been highly favorable to customers.

VI. REVENUE ALLOCATIONS AND RATES

Q. Mr. Seelye's rebuttal testimony addresses intervenors' arguments concerning the Companies' proposed revenue allocations and rates, including the Companies' proposed residential Basic Service Charges. Do you have any comment on that testimony?

A. Yes. As Mr. Seelye notes in his rebuttal testimony, there is relative consensus among intervenor witnesses who have offered testimony on cost of service studies that the

Companies' studies are reasonable. The exception to that consensus is the Attorney General's witness Glen Watkins, whose testimony Mr. Seelye addresses at length.

But consensus about cost of service does not lead to consensus about revenue allocation. Unsurprisingly, various intervenors have proposed revenue allocations that tend to favor the parties they represent. The Companies' revenue allocations are therefore something of a middle ground, which I believe demonstrates the reasonableness of those allocations. Therefore, I recommend the Commission accept the Companies' proposed revenue allocations for the reasons stated in Mr. Seelye's direct and rebuttal testimony.

Regarding rates, Mr. Seelye's rebuttal testimony shows the reasonableness of the Companies' proposed rates based on the Companies' proposed revenue allocations. In particular, I agree with Mr. Seelye's responses to intervenors' arguments concerning the Companies' proposed residential Basic Service Charges. The Companies' proposed Basic Service Charges move toward cost of service while retaining ample incentives for customers to engage in conservation and energy efficiency efforts. For higher-usage customers, such as those who receive third-party assistance, Basic Service Charges that more closely reflect cost of service actually help reduce their bills on a relative basis. Therefore, I support Mr. Seelye's testimony on these points and the Companies' proposed rates, including the Companies' proposed residential Basic Service Charges.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 7th day of April 2021.

Judy Schooler

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

POWER PURCHASE AGREEMENT

AMONG

RHUDES CREEK SOLAR, LLC,

LOUISVILLE GAS AND ELECTRIC COMPANY

AND

KENTUCKY UTILITIES COMPANY

November 21, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

Power Purchase Agreement among Rhudes Creek Solar, LLC, Louisville Gas and Electric Company, and Kentucky Utilities Company

This Power Purchase Agreement (this "PPA") is made as of November 21, 2019, by and among (i) **Rhudes Creek Solar, LLC** ("Seller"), a Delaware limited liability company with a principal place of business at c/o ibV Energy Partners LLC, 777 Brickell Ave., Suite 500, Miami, FL 33131, (ii) **Louisville Gas and Electric Company** ("LG&E"), a Kentucky corporation with a principal office at 220 West Main Street, Louisville, Kentucky 40202, and (iii) **Kentucky Utilities Company** ("KU"), a Kentucky and Virginia corporation with its principal office at One Quality Street, Lexington, Kentucky 40507. LG&E and KU are sometimes hereinafter referred to individually as "Buyer" and collectively (and severally liable as provided in Section 12.6 below) as the "Buyers."

WHEREAS, Seller desires to develop, design, construct, own or lease, and operate a solar photovoltaic electric generating facility in Hardin County, Kentucky with an expected total maximum power output of approximately but not more than 100 MWac and not less than the Minimum Demonstrated Capacity, and which is defined below as the "Facility"; and

WHEREAS, Seller desires to sell and deliver to Buyers at the Point of Interconnection the Solar Energy Output generated by the Facility and any Renewable Energy Benefits associated with such Solar Energy Output.

NOW, THEREFORE, in consideration of the premises and the mutual covenants and conditions herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following:

ARTICLE 1
Definitions and Rules of Interpretation

1.1 Rules of Construction. The capitalized terms listed in this Article shall have the meanings set forth herein whenever the terms appear in this PPA, whether in the singular or the plural or in the present or past tense. Other terms used in this PPA but not listed in this Article shall have meanings as commonly used in the English language and, where applicable, in Prudent Industry Practice. Words not otherwise defined herein that have well known and generally accepted technical or trade meanings are used herein in accordance with such recognized meanings. In addition, the following rules of interpretation shall apply:

(A) The masculine shall include the feminine and neuter.

(B) Unless such a reference states otherwise, references to "Articles," "Sections," or "Exhibits" shall be to articles, sections, or exhibits of this PPA.

(C) The Exhibits attached hereto are incorporated in and are intended to be a part of this PPA; provided, that in the event of a conflict between the terms of any Exhibit and the body of this PPA, the body of this PPA shall take precedence.

(D) This PPA was negotiated and prepared by both Parties with the advice and participation of counsel. The Parties have agreed to the wording of this PPA and none of the provisions hereof shall be construed against one Party on the ground that such Party is the author of this PPA or any part hereof.

(E) Except with respect to any provision of this Agreement stating that a Party may exercise its sole discretion, (i) the Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this PPA. Unless expressly provided otherwise in this PPA, (ii) where the PPA requires the consent, approval, or similar action by a Party, such consent or approval shall not be unreasonably withheld, conditioned or delayed, and (iii) wherever the PPA gives a Party a right to determine, require, specify or take similar action with respect to a matter, such determination, requirement, specification or similar action shall be reasonable.

(F) Use of the words “include” or “including” or similar words shall be interpreted as “including but not limited to” or “including, without limitation.”

(G) The words “shall” and “will” have equal force and effect.

(H) The words “herein,” “hereof,” or “hereunder” or similar terms refer to this PPA as a whole and not to any specific section or article.

1.2 <u>Interpretation with Interconnection Agreement</u>.

(A) The Parties recognize that Seller will enter into a separate Interconnection Agreement with the Interconnection Provider. Notwithstanding any other provision in this PPA, nothing in the Interconnection Agreement, nor any alleged event of default thereunder, shall alter or modify Seller’s or Buyers’ rights, duties and obligations under this PPA, and nothing in this Agreement, nor any alleged event of default hereunder, shall alter or modify the rights, duties and obligations of Seller or the Interconnection Provider under the Interconnection Agreement.

(B) Except and only to the extent expressly stated otherwise herein, Seller expressly recognizes that, for purposes hereof, the Interconnection Provider and shall be deemed to be a separate entity and separate contracting party from Buyers whether or not the Interconnection Agreement is entered into with a Buyer or an Affiliate of Buyer, in its capacity as the Interconnection Provider. Seller acknowledges that Buyers, acting in their capacity as the purchasers hereunder, have no responsibility for or control over Interconnection Provider, and are not liable under this Agreement for any breach of any obligation or duty of the Interconnection Provider under the Interconnection Agreement.

1.3 <u>Interpretation of Arrangements for Utility Supply to the Facility</u>. This PPA does not provide for the supply of retail electric power or natural gas to the Facility (“House

Energy"). Seller shall contract with the local utility in whose retail service territory the Facility is located ("Local Provider") for the supply of House Energy. If a Buyer is the Local Provider, Seller's arrangements for the supply of House Energy to the Facility and this PPA shall be separate and free-standing arrangements. For purposes of this PPA, the Local Provider shall be treated as a separate entity and separate contracting party, whether or not the Local Provider is a Buyer or an Affiliate of a Buyer. Notwithstanding any other provision in this PPA, nothing in Seller's arrangements for the supply of House Energy to the Facility shall alter or modify Seller's or Buyers' rights, duties and obligations under this PPA.

1.4 Definitions. The following terms shall have the meanings set forth herein:

"Abandonment" means (a) the relinquishment of all possession and control of the Facility by Seller, other than pursuant to a transfer permitted under this Agreement, or (b) if after commencement of the construction of the Facility, and prior to the Commercial Operation Date, there is a complete cessation of the construction and testing of the Facility for 90 consecutive days by Seller and Seller's contractors, but only if such relinquishment or cessation is not caused by or attributable to an Event of Default of either Buyer, or by an event of Force Majeure.

"Additional Maintenance Outages" has the meaning assigned to it in Section 10.5 hereof.

"Affiliate" means, with respect to any Person, each Person that directly or indirectly controls or is controlled by or is under common control with such Person. For the purposes of this definition, "control" (including the terms "controls", "under the control of", "controlled by", and "under common control with"), as used with respect to any Person, shall mean the possession, directly or indirectly, of the power to direct or cause the direction of the management of the policies of such Person, whether through ownership interest, by contract or otherwise.

"Agreement" means this Power Purchase Agreement together with the Exhibit(s) and Schedule(s) attached hereto, as such may be amended from time to time.

"A.M. Best" means A.M. Best Company, Inc. and its affiliates.

"Applicable Law" means all applicable laws, statutes, treaties, codes, ordinances, regulations, certificates, orders, licenses and permits of any Governmental Authority and all Non-Governmental Compliance Obligations, now in effect or hereafter enacted, amendments to any of the foregoing, interpretations of any of the foregoing by a Governmental Authority having jurisdiction, and all applicable judicial, administrative, arbitration and regulatory decrees, judgments, injunctions, writs, orders, awards or like actions (including those relating to human health, safety, the natural environment or otherwise).

"Availability" for a period means, the ratio, expressed as a percentage, of (a) for the actual Solar Energy Output during such period over (b) the Expected Amount for such period.

"Availability Cure" means the occurrence of an Availability Satisfactory Day after an Availability Unsatisfactory Day.

"Availability Day" means any Day after the date sixty (60) days following the Commercial Operation Date and before the end of the Term.

"Availability Default Period" means, with regard to an Availability Unsatisfactory Day, the period starting the day after such Availability Unsatisfactory Day and ending on the day that is sixty (60) Availability Days following the receipt by Seller of an Availability Underperformance Notice with regard to such Availability Unsatisfactory Day; provided that an Availability Day shall not be counted toward such sixty (60) Availability Days if it (i) falls within an Excused Maintenance Outage scheduled in accordance with Section 10.4(A) and, if changed in accordance with Section 10.4(C), changed before the Availability Unsatisfactory Day on which the start of such sixty (60) Availability Days is based, or (ii) consists entirely of Seller Uncontrollable Minutes.

"Availability LD Cure Period" means, with regard to an Availability Unsatisfactory Day, the period starting the day after such Availability Unsatisfactory Day and ending on the day that is thirty (30) Availability Days following the receipt by Seller of an Availability Underperformance Notice with regard to such Availability Unsatisfactory Day; provided that an Availability Day shall not be counted toward such thirty (30) Availability Days if it (i) falls within an Excused Maintenance Outage scheduled in accordance with Section 10.4(A) and, if changed in accordance with Section 10.4(C), changed before the Availability Unsatisfactory Day on which the start of such thirty (30) Availability Days is based, or (ii) consists entirely of Seller Uncontrollable Minutes.

"Availability Satisfactory Day" means an Availability Day on which the Availability of the Facility is at least [redacted] percent ([redacted]%) of the Expected Amount for such Availability Day.

"Availability Underperformance Notice" has the meaning ascribed in Section 8.3(B).

"Availability Unsatisfactory Day" means an Availability Day on which the Availability of the Facility is less than [redacted] percent ([redacted]%) of the Expected Amount for such Availability Day.

"Avoided Energy Cost" means Buyer's avoided energy cost per MWh set in the Buyers' Standard Rate Rider LQF or a successor provision of Buyers' tariffs, expressed in Dollars.

"Business Day" means any calendar Day that is not a Saturday, a Sunday, or a NERC, state and/or federal recognized holiday where banks are permitted or authorized to close in Kentucky.

"Buyer" and "Buyers" is defined in the preamble of this Agreement, and includes such Person's permitted successors and assigns.

"Buyer Entities" has the meaning ascribed to it in Section 17.1.

"Buyers' Conditions Precedent" is defined in Section 6.2.

"Buyers' Tier 1 CP" is defined in Section 6.2.

"Buyers' Tier 1 CP Confirmation Notice" has the meaning ascribed to it in Section 6.3.

"Buyers' Tier 3 CPs" is defined in Section 6.2.

"Buyers' Tier 3 CP Confirmation Notice" has the meaning ascribed to it in Section 6.3.

"Capacity Rights" means any current or future defined characteristic, certificate, tag (but not Renewable Energy Benefits), credit, ancillary service or attribute thereof, or accounting construct, including any of the same counted towards any current or future resource adequacy or reserve requirements, associated with the electric generation capability and capacity of the Facility or the Facility's capability and ability to produce energy; provided, that Capacity Rights shall not include any ancillary services that Seller is expressly obligated to provide to the Interconnection Provider pursuant to the terms of the Interconnection Agreement. Capacity Rights do not include any Tax Credits, or any other tax incentives existing now or in the future associated with the construction, ownership or operation of the Facility.

"Change in Applicable Law" means the enactment, adoption, promulgation, implementation, or issuance of, or a new or changed interpretation of, any Applicable Law or Non-Governmental Compliance Obligation that takes effect after the Effective Date, including Applicable Laws regarding Renewable Energy Benefits, Taxes, and/or the generation and sale of electricity and/or Non-Governmental Compliance Obligations.

"Code" means the U.S. Internal Revenue Code of 1986, including applicable rules and regulations promulgated thereunder, as amended from time to time.

"Commercial Operation" is defined in Section 4.2.

"Commercial Operation Date" means the date on which Commercial Operation is achieved.

"Commission Approvals" means such approvals from the PSC or the Virginia State Corporation Commission, as Buyers choose to pursue in their sole discretion, with respect to the performance of Buyers' obligations and recovery of costs incurred hereunder, all without any requirement to modify the terms of this Agreement and without any conditions unacceptable to Buyer in its sole discretion.

"Commissioning" or "Commissioned" means, with respect to the Facility or any part thereof, the commencement of the period during which the Facility or a part thereof has begun Testing and ending when the Facility or part thereof has been approved for the production of Solar Energy and authorized to commence delivery of Solar Energy Output, provided, however, that for certain tax and other corporate purposes, in accordance with Applicable Law, Commissioning shall be deemed to occur when any measurable amount of Solar Energy Output is first generated at the Facility and delivered and sold to Buyers consistent with the provisions of this PPA.

"Commissioning Tests" has the meaning assigned to it in Section 10.2.

"Confidential Information" has the meaning ascribed to it in Section 20.12(F).

"CP Confirmation Notice" means any notice defined in Section 6.3 and having "CP Confirmation Notice" as part of the term by which it is defined.

"Credit Event" shall mean, with regard to a Buyer: (x) if the credit rating then assigned to such Buyer's unsecured, senior long-term debt or deposit obligations (not supported by third party credit enhancement) or other primary debt security is reduced to below an Investment Grade Rating by a Credit Rating Agency, or any Credit Rating Agency has suspended or withdrawn such unenhanced credit rating for credit-related reasons, (y) the rating assigned to a Buyer's senior unsecured long-term debt obligations (not supported by third party credit enhancements) or, if the Buyer does not have a rating for its senior unsecured long-term debt, then the rating assigned to such Buyer by a Credit Rating Agency, is reduced to below an Investment Grade Rating; or (z) if such Buyer does not make payment to Seller when due more than once in any twelve (12) month period and such Buyer does not prepare a cure plan to insure compliance with the payment requirements under this PPA that is satisfactory to Seller within five (5) Days of such late payment.

"Credit Rating Agency" or "CRA" means a nationally recognized statistical rating organization ("NRSO"), which is a credit rating agency ("CRA") that issues credit ratings that the United States Securities and Exchange Commission permits other financial firms to use for certain regulatory purposes. Among the 10 designated CRA's by the NRSO, Buyers and Seller shall rely on ratings provided by one or more ratings issued by the Big Three credit rating agencies, Standard & Poor's (S&P), Moody's and Fitch Group, as it pertains to Letter(s) of Credit and A.M. Best as it pertains to Surety Bonds. If no such rating is provided by the aforementioned CRAs, Buyer and Seller shall find a CRA and/or do credit due diligence as mutually agreed upon by the Parties.

"Curtailed Energy" has the meaning ascribed to it in Section 8.2(A).

"Curtailed Renewable Energy Benefits" has the meaning ascribed to it in Section 8.2(A).

"Day" means a period beginning at 12:00 a.m. EST on any Day and ending at 11:59:59 p.m. EST on such Day.

"Demonstrated Capacity" means the Facility's actual net generating nameplate capacity rating, measured in MWac, as determined by the Commissioning Tests.

"Designated Network Resource" has the meaning assigned to it in the Interconnection Provider's open access transmission tariff.

"Disclosing Party" has the meaning ascribed to it in Section 20.12(A).

"Disputing Party" has the meaning assigned to it in Section 9.5 hereof.

"Dollars" means the lawful currency of the United States of America.

"Early Termination Date" has the meaning ascribed to it in Section 12.4(A).

"Effective Date" means the date first written above.

"Electric Metering Device(s)" means all metering and data processing equipment used to measure, record, or transmit data relating to the Solar Energy Output generated by the Facility. Electric Metering Devices include the meter, the metering current transformers and the metering voltage transformers.

"Emergency Condition" means a condition or situation that presents an imminent physical threat of danger to life, health or property, and/or could reasonably be expected in the opinion of the Interconnection Provider to cause a significant disruption to the Interconnection System or otherwise be required in accordance with the requirements of the NERC, SERC, or the Reliability Coordinator, or any system condition not consistent with Prudent Industry Practices.

"EPC Contract" means the engineering, procurement and construction contract(s) or other similar documents entered into by Seller in relation to the engineering, procurement and construction of the Facility.

"EST" means Eastern Standard Time.

"Event of Default" has the meaning set forth in Article 12.

"Excess Solar Energy" means any incremental Solar Energy Output beyond the Maximum Production Amount during any Year.

"Excess Solar Energy Payment Rate" means a rate equal to [redacted] percent ([redacted]%) of the Solar Energy Payment Rate.

"Excused Maintenance Outage" means: (1) Scheduled Maintenance Outages outside the Non Scheduled Maintenance Period; and (2) up to thirty (30) hours per calendar year of Scheduled Maintenance Outages during the Non-Scheduled Maintenance Period.

"Expected Amount" with respect to a period shall mean the quantity of Solar Energy Output expressed in MWh that would have been produced by the Facility during such period, except MWh that would have been produced by the Facility any portions of such period which are during Excused Maintenance Outages or Seller Uncontrollable Minutes, if the Facility operated at 100% of the Facility Capacity in MWac throughout such period, except any portions of such period which are during Excused Maintenance Outages or Seller Uncontrollable Minutes, using the Production Model.

"Facility" means Seller's solar electric generating facility and Seller's Interconnection Facilities, as identified and described in Article 3, including all of the following, the purpose of which is to produce electricity and deliver such electricity to the Point of Interconnection: Seller's equipment, buildings, all of the generation facilities, including step-up transformers, output breakers, facilities necessary to connect to the Point of Interconnection, protective and associated equipment, improvements, and other tangible assets, contract rights, easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation, and maintenance of the electric generating facility that produces the Solar Energy Output subject to this PPA.

"Facility Capacity" means 100 MWac, which Facility Capacity may be adjusted pursuant to Section 3.3.

"FERC" means the Federal Energy Regulatory Commission or any successor agency.

"Financial Closing" means the fulfillment of each of the following conditions:

(A) the execution and delivery of the Financing Documents; and

(B) all conditions precedent to the initial availability for disbursement of funds under the Financing Documents (other than relating to the effectiveness of this PPA) are satisfied or waived.

"Financing Documents" means the loan and credit agreements, notes, bonds, indentures, sale-leaseback agreements, guarantees, security agreements, lease financing agreements, partnership and limited liability company operating agreements, mortgages, deeds of trust, interest rate exchanges, swap agreements and other documents relating to the development, bridge, construction and/or permanent debt and/or equity financing (including the monetization of Tax Credits and accelerated depreciation by equity investment, issuance of cash in lieu of Tax Credits and/or sale-leaseback agreements) for the Facility, including any credit enhancement, credit support, working capital financing, or refinancing documents, and any and all amendments, modifications, or supplements to the foregoing that may be entered into from time to time at the discretion of Seller or its Affiliates in connection with development, construction, ownership, leasing, operation or maintenance of the Facility.

"Financing Parties" means the Persons (including any trustee or agent on behalf of such Persons) providing financing or refinancing to or on behalf of Seller or its

Affiliates, whether debt or equity, or a combination thereof, for the design, development, construction, Testing, Commissioning, operation and maintenance of the Facility (whether limited recourse, or with or without recourse).

"Fitch Group" means Fitch Ratings, Inc., Fitch Ratings, Ltd. and their affiliates or their successors.

"Force Majeure" has the meaning set forth in Section 14.1(A).

"Forced Outage" means a reduction of, or cessation in the delivery of, or inability to deliver, Solar Energy Output that is not the result of (i) a Scheduled Maintenance Outage, (ii) a Force Majeure event, (iii) a Seller Delivery Excuse, (iv) an Emergency Condition, or (v) changes in weather and ambient conditions.

"Governmental Approval" means any authorization, consent, permission, approval, license, ruling, permit, exemption, variance, order, judgment, instruction, condition, direction, directive, decree, declaration of or regulation by any Governmental Authority, including: (i) with regard to Seller, relating to the construction, development, ownership, occupation, start-up, Testing, operation or maintenance of the Facility, or (ii) with regard to each Buyer, the execution, delivery or performance of this PPA or the procurement pursuant to this PPA of the Solar Energy Output and the Renewable Energy Benefits and recovery of the related costs. Governmental Approval shall also mean, where and as applicable and the context so dictates, any and all authorization, consent, permission, approval, license, ruling, permit, exemption, variance, order, judgment, instruction, condition, direction, directive, decree, declaration of or regulation with regard to any Non-Governmental Compliance Obligations.

"Governmental Authority" means any federal, state, local or municipal governmental body; any governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power; or any court or governmental tribunal.

"House Energy" has the meaning assigned to it in Section 1.3.

"Indemnified Party" means the Buyer Entities entitled to indemnification by Seller under Section 17.1(B), or the Seller Entities entitled to indemnification under Section 17.1(C), as appropriate.

"Independent Transmission Organization" or "ITO" means an entity authorized by FERC to administer Buyers' open access transmission tariff.

"Interconnection Agreement" means the separate agreement between Seller and the Interconnection Provider for interconnection of the Facility to the Interconnection Provider's System, as such agreement may be amended from time to time; provided, however, that a provisional interconnection agreement executed prior to the completion of all system impact and facility studies shall not be considered to be an Interconnection Agreement.

"Interconnection Facilities" means Interconnection Provider's Interconnection Facilities and Seller's Interconnection Facilities.

"Interconnection Provider" means the entity that owns, leases, or otherwise controls the electric transmission facilities to which Seller proposes to interconnect.

"Interconnection Provider's Interconnection Facilities" means the facilities and equipment installed by the Interconnection Provider after the Point of Interconnection for the direct purpose of interconnecting the Facility with the Interconnection Provider's System. Arrangements for the installation and operation of the Interconnection Provider's Interconnection Facilities shall be governed by the Interconnection Agreement.

"Interconnection Provider's System" means the contiguously interconnected electric transmission, including Interconnection Provider's Interconnection Facilities, over which the Interconnection Provider has rights (by ownership or contract) to provide bulk transmission of capacity and energy from the Point of Interconnection.

"Interim Interconnection Service" means Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Interconnection Provider's system and be eligible to deliver the Generating Facility's electric output on a temporary basis while the Interconnection Customer's Generator Interconnection Request is being processed through the LGIP.

"Interim LGIA" means the agreement that governs the provision of Interim Interconnection Service**,** to include a Provisional LGIA or an Interim LGIA, as defined by the Interconnection Provider's open access transmission tariff.

"Investment Grade Rating" means as the rating designated by one of the Credit Rating Agencies with a minimum long term issuer rating (≥):

- As it pertains to Letter(s) of Credit:
  - o BBB- from S&P; or
  - o Baa3 from Moody's; or
  - o BBB- from Fitch Group;
- As it pertains to Surety Bonds:
  - o bbb- from A.M. Best;
- As it relates to a Buyer, a minimum investment grade rating defined as:
  - o BBB- from S&P; or
  - o Baa3 from Moody's; or
  - o BBB- from Fitch Group;

"KU Percentage" means 61%.

"kW" means one or more kilowatts of electricity, as the context requires.

"Large Generator Interconnection Agreement" (LGIA) shall mean the form of interconnection agreement applicable to an Generator Interconnection Request pertaining to a Large Generating Facility that is included in the Interconnection Provider's tariff.

"Large Generator Interconnection Procedures" (LGIP) shall mean the interconnection procedures applicable to an Generator Interconnection Request pertaining to a Large Generating Facility that are included in the Interconnection Provider's tariff.

"LD Avoided Cost Input" means with respect to an Availability Day the greater of (i) zero or (ii) the amount that results from subtracting the Solar Energy Payment Rate from Avoided Energy Cost as of such Availability Day.

"LD Monetary Factor" has the meaning set forth in Section 8.3(C).

"LD REC Input" means with respect to an Availability Day the lowest available offer or ask price of a green-e certified REC in Kentucky and its adjoining states and such other states, if any, which Buyers agree in writing to include for such purpose, as of such Availability Day.

"LG&E Percentage" means 39%.

"Local Provider" has the meaning assigned to it in Section 1.3.

"Maximum Production Amount" means a production amount of [redacted] MWh during a Year.

"Minimum Demonstrated Capacity" means [redacted] MWac.

"Monthly Billing Period" means the period during any particular calendar month in which either Test Energy and/or Solar Energy Output has been generated by Seller for Buyers and delivered to the Point of Interconnection for sale to Buyers, whether or not occurring prior to or subsequent to the Commercial Operation Date.

"Moody's" means Moody's Investors Service, Inc. Moody's Analytics, Inc. and their affiliates.

"Month" means a calendar month.

"MW" means megawatt or one thousand kW.

"MWac" means megawatt alternating current.

"MWh" means megawatt hours.

"NERC" means the North American Electric Reliability Council or any successor organization.

"Non-Governmental Compliance Obligations" means all obligations to comply with existing national and regional reliability standards and rules and regulations related to transmission system reliability and set by entities that are not Governmental Authorities, including standards set by NERC, Seller's ITO, and any RE and any successor agencies.

"Non-Scheduled Maintenance Period" has the meaning assigned to it in Section 10.4(A).

"O&M Records" has the meaning assigned to it in Section 13.2(A).

"Party" and "Parties" have the meanings set forth in the preamble above.

"Person" means any natural person, corporation, limited liability company, general partnership, limited partnership, proprietorship, other business organization, trust, union, association or Governmental Authority.

"Point of Interconnection" means the electric system point at which Seller makes available to Buyer and delivers to Buyer the Solar Energy Output being provided by Seller to Buyer under this PPA. The Point of Interconnection is also the physical point at which electrical interconnection is made between the Facility and the Interconnection Provider's System.

"PPA" means this Agreement.

"Prime Rate" shall mean the prime rate (or base rate) reported in the Money Rates column or section of The Wall Street Journal as being the base rate on corporate loans at large U.S. money center commercial banks (whether or not such rate has actually been charged by any such bank) on the first day on which The Wall Street Journal is published in the month in which the subject sums are payable or incurred.

"Production Model" means an as-built energy model prepared by the Seller's construction lender's independent engineer, which model shall include the variables and use the methodology set forth on Exhibit D, and such other variables as such independent engineer determines should be included, and such other adjustments as the Parties may mutually determine.

"Projected Schedule" has the meaning assigned to it in Section 7.2(A).

"Provisional Generator Interconnection Agreement" means the interconnection agreement for Provisional Interconnection Service established between Interconnection Provider's and the Interconnection Customer. This agreement shall take the form of the Large Generator Interconnection Agreement, modified for provisional purposes.

"Prudent Industry Practice(s)" means those practices, methods, equipment, specifications and standards of safety and performance, as the same may change from time to time, as are commonly used by operators of utility electric generation stations of a type and size similar to those constituting the Facility, which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result at a reasonable cost, consistent with good, safe, and prudent engineering practices in connection with the operation, maintenance, repair, and use of equipment and facilities and commensurate standards of safety, performance, dependability, efficiency, and economy that conform to all material operation and maintenance standards recommended by the Facility's equipment suppliers and manufacturers and Applicable Law. Prudent Industry Practices are not intended to be limited to the optimum practice or method to the exclusion of others, but rather to be a spectrum of possible but reasonable practices and methods.

"PSC" means the Kentucky Public Service Commission and any successor entity thereto.

"Receiving Party" has the meaning ascribed to it in Section 20.12(A).

"Receiving Party's Representatives" has the meaning assigned to it in Section 20.12(B).

"Reliability Coordinator" means the entity that is the highest level of authority responsible for the reliable operation of the transmission system, has the wide area view of the transmission system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations.

"Renewable Energy Benefits" means any and all renewable and environmental attributes, emissions reductions, credits, offsets, allowances reporting rights and benefits, howsoever entitled, associated with the production of the Solar Energy Output, and includes any and all Renewable Energy Certificates and Renewable Energy Benefits Reporting Rights. Renewable Energy Benefits exclude and do not include any Tax Credits or other tax incentives existing now or in the future associated with the construction, ownership or operation of the Facility.

"Renewable Energy Benefits Reporting Rights" means the exclusive right of a purchaser of Renewable Energy Benefits to report exclusive ownership of Renewable Energy Benefits in compliance with federal or state Law, if applicable, and to federal or state agencies or other parties at such purchaser's discretion, and include reporting under Section 1605(b) of the Energy Policy Act of 1992, under regulations of the Environmental Protection Agency under Clean Air Act Amendments Section 111(d), and under any present or future domestic, international, or foreign emissions trading program or renewable portfolio standard.

"Renewable Energy Certificate" or "REC" means a unit that represents all of the non-power attributes from one MWh of electricity generation from a renewable generating unit including the property rights to the environmental, social and other non-power attributes of a renewable electricity generation portfolio energy system or efficiency measure that the Facility is entitled to receive pursuant to Applicable Law, including the Renewable Energy Law.

"Renewable Energy Law" means an act of the Kentucky Legislature, if any, relating to energy and requiring certain providers of electric service to comply with the portfolio standard for renewable energy, and providing for other matters relating thereto, in each case as such Laws, regulations, guidance and requirements may be amended, preempted or superseded.

"Required Commercial Operation Date" means December 31, 2021, subject to adjustment as described in Section 4.1.

"Restoration" has the meaning assigned to it in Section 14.5(B).

"Restoration Report" has the meaning assigned to it in Section 14.7.

"Restoration Schedule" has the meaning assigned to it in Section 14.5(B).

"RE" means any regional entity with jurisdiction over Seller as a generator of electricity and operator of the Facility.

"SCC" means system control center, the Buyers' representative(s) responsible for dispatch of generating units and scheduling energy and capacity from the Facility.

"Scheduled Maintenance Outage" means a time during which the Facility is shut down or its output reduced to undergo scheduled maintenance in accordance with this PPA, or as otherwise agreed by Seller and Buyers.

"Seller's Conditions Precedent" is defined in Section 6.1.

"Seller's Interconnection Facilities" means the equipment between the single collection point for the A/C wiring from the output of the project inverters and the Point of Interconnection as well as all transmission facilities required to access the Interconnection Provider's System at the Point of Interconnection, along with any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of such facilities. On the low side of the step-up transformer, it includes Seller's relays, and load control equipment as provided for in the Interconnection Agreement.

"Seller's Tier 1 CPs" is defined in Section 6.1.

"Seller's Tier 2 CP" is defined in Section 6.1.

"Seller's Tier 3 CPs" is defined in Section 6.1.

"Seller's Tier 4 CP" is defined in Section 6.1.

"Seller's Tier 1 CP Confirmation Notice" has the meaning ascribed to it in Section 6.3.

"Seller's Tier 2 CP Confirmation Notice" has the meaning ascribed to it in Section 6.3.

"Seller's Tier 3 CP Confirmation Notice" has the meaning ascribed to it in Section 6.3.

"Seller's Tier 4 CP Confirmation Notice" has the meaning ascribed to it in Section 6.3.

"Seller Credit Support" has the meaning ascribed to it in Section 11.1.

"Seller Delivery Excuse" shall mean: (i) any breach by a Buyer of its obligations under the PPA, (ii) any delay or failure by a Buyer in giving any approval such Buyer is required to give under this PPA by the time by which such Buyer required is required to give such approval under this PPA, or (iii) any delay or failure of a Buyer to accept Solar Energy Output or Renewable Energy Benefits as required under this PPA (1) because of any failure of such Buyer to obtain or maintain adequate transmission arrangements, or (2) because of any failure of such Buyer to comply with Applicable Law; in each case, to the extent that any of the foregoing actually and proximately prevents the Seller, in whole or in part, from performing any of its obligations or satisfying any conditions under this PPA.

"Seller Entities" has the meaning ascribed to it in Section 17.1.

"Seller Uncontrollable Minutes" means a reduction of, or cessation in the delivery of, or inability to deliver, Solar Energy Output that would not occur but for one or more of (i) a Force Majeure event, (ii) a Seller Delivery Excuse, (iii) an Emergency Condition, or (iv) to the extent not caused by Seller's actions, any curtailment of the Facility by a Buyer, an ITO, the Interconnection Provider or any other Person or the Interconnection Provider; provided, however, that if any of the events described above in items (i) through (iv) occur simultaneously, then the relevant period of time shall only be counted once in order to prevent double counting. Seller Uncontrollable Minutes shall not include minutes when (i) the Facility or any portion thereof was unavailable solely due to Seller's non-conformance with the Interconnection Agreement or (ii) the Facility or any portion thereof was paused or withdrawn from use by Seller for reasons other than those covered in this definition.

"SERC" means SERC Reliability Corporation or any successor entity.

"Site" means the parcel of real property on which the Facility will be constructed and located, including any easements, rights of way, surface use agreements and other interests or rights in real estate reasonably necessary for the construction, operation and maintenance of the Facility.

"Solar Energy" means the electric energy generated by the Facility using solar electric generation technologies.

"Solar Energy Output" means the net unit contingent electric energy generated in MWh using solar electric generation technologies delivered at nominal voltage to the Point of Interconnection as measured by the Electric Metering Devices installed pursuant to Section 5.3. Solar Energy Output shall be of a power quality of 60 cycle, three-phase alternating current that is compliant with the Interconnection Agreement.

"Solar Energy Payment" has the meaning assigned to it in Section 8.1(A).

"Solar Energy Payment Rate" means $27.82/MWh.

"Standard and Poor's" or "S&P" means Standard and Poor's Ratings Group, a division of McGraw Hill, Inc. and any successor entity thereto.

"Surety Bond" means a bond that is issued by a surety or insurance company that promises to pay a specified amount to Buyers upon certain events, which include, but are not limited to, when the Seller fails to perform a payment obligation under this Agreement and which the surety or insurance company so issuing shall (i) be authorized to issue surety bonds in the Commonwealth of Kentucky, (ii) have assets of at least [redacted] and (iii) have an Investment Grade Rating as defined in this Agreement.

"Tax Credits" means investment tax credits under Section 48 of the Code as in effect on the date of this PPA, and any successor or other provision providing for a federal, state or local tax credit, cash grant, tax exemption, depreciation, tax attribute or benefit or similar program determined by reference to ownership of renewable energy production facilities, renewable electric energy produced from Solar Energy or amounts invested in renewable energy generating facilities.

"Taxes" means all taxes, fees, levies, licenses or charges imposed by any Governmental Authority, other than taxes, levies, licenses or charges based upon net income or net worth.

"Term" means the period during which this PPA shall remain in full force and effect, and which is further defined in Article 2.

"Test" or "Testing" means those tests, evaluations and measurements of the Facility's output capability that are undertaken in connection with the Commissioning of the Facility pursuant to Section 10.2 of this PPA, which shall include such tests as are consistent with Prudent Industry Practices and that are required by the Financing Documents, applicable permits, and the EPC Contract.

"Test Date" means the date on which Seller shall commence Commissioning of the Facility.

"Test Energy" means the Solar Energy Output that is generated by the Facility, delivered to Buyers at the Point of Interconnection, and purchased by Buyers, pursuant to Section 10.2(C) and Section 4.3.

"Test Period Transmission Service" means transmission service which would allow energy to flow from the Point of Interconnection to the Buyers' load.

"Tier 1 CP Termination Notice" has the meaning ascribed to it in Section 6.3.

"Tier 2 CP Termination Notice" has the meaning ascribed to it in Section 6.3.

"Tier 3 CP Termination Notice" has the meaning ascribed to it in Section 6.3.

"Tier 4 CP Termination Notice" has the meaning ascribed to it in Section 6.3.

"Year" means a calendar year.

ARTICLE 2
Term and Termination

This PPA shall become effective as of the Effective Date and shall remain in full force and effect until the twenty (20) year anniversary of the Commercial Operation Date, subject to early termination or any extension provisions set forth herein. Applicable provisions of this PPA shall continue in effect after termination, including early termination, to the extent necessary to enforce or complete the duties, obligations or responsibilities of the Parties arising prior to termination and, as applicable, to provide for: final billings and adjustments related to the period prior to termination, repayment of any money due and owing to either Party pursuant to this PPA, repayment of principal and interest associated with security funds, and the indemnifications specified in this PPA. The Term of this PPA may be extended only upon the written agreement of Seller and Buyers.

ARTICLE 3
Facility Description

3.1 <u>Summary Description</u>. Subject to the satisfaction or waiver of the Seller's CPs, Seller shall construct, own, operate, and maintain the Facility and associated equipment having an aggregate maximum power output of the Facility Capacity.

3.2 <u>General Design of the Facility</u>. Seller shall construct the Facility in accordance with Prudent Industry Practice(s) and in compliance with the terms and conditions of the Interconnection Agreement, Applicable Law, and applicable Permits. During Commercial Operation, Seller shall maintain the Facility according to Prudent Industry Practice(s) and the Interconnection Agreement. In addition to the requirements of the Interconnection Agreement, the Facility shall at all times:

(A) have the required panel space to accommodate metering, generator telemetering equipment and communications equipment;

(B) have remote monitoring facilities; and

(C) have no fewer than four (4) suitable solar radiation meters necessary to characterize the solar resource and site ambient conditions, including plane of array irradiance (POAI), global horizontal irradiance (GHI), temperature, pressure and humidity.

3.3 Facility Capacity Adjustment.

(A) If Seller has executed an Interim LGIA prior to the start of construction of the Facility, Seller may, during its use of Interim Interconnection Service, decrease the Facility Capacity to the amount permitted to be interconnected pursuant to such Interim LGIA by providing Buyers with written notice of such adjustment. In such event, the Facility Capacity shall, during Seller's use of Interim Interconnection Service, be no less than [redacted] percent ([redacted]%) of the amount allowed under the Interim LGIA. Seller shall thereafter be entitled to increase the Facility Capacity up to the amount that Seller is authorized to interconnect pursuant to an LGIA to be executed by Seller (but not to exceed 100 MWac).

(B) Unless decreased as set forth in this Section 3.3(B), the Facility Capacity following the Commercial Operation Date, except during Interim Interconnection Service, shall be 100 MWac. Prior to Seller's notice to its EPC contractor to commence construction, Seller may, on one occasion only, decrease the Facility Capacity by providing Buyer with written notice of such adjustment; provided, however, that Seller may not decrease the Facility Capacity to below the Minimum Demonstrated Capacity without Buyer's prior written consent, which Buyer may withhold in its sole discretion.

ARTICLE 4
Commercial Operation

4.1 Completion by Required Completion Date.

(A) Seller shall cause the Facility to achieve the Commercial Operation Date no later than the Required Commercial Operation Date; provided, that Seller shall not be obligated to establish a Commercial Operation Date under this PPA that is earlier than the Required Commercial Operation Date.

(B) The Required Commercial Operation Date shall be extended, day-for-day, for (i) each day during which a Force Majeure event has occurred and is continuing (but not more than a maximum of 180 Days for all events of Force Majeure in the aggregate); (ii) each Day after a date on or before which Section 6.2 states that a Buyers' Conditions Precedent should occur and before the date that Buyers deliver Buyers' CP Confirmation Notice with respect to such Buyers' Conditions Precedent; and (iii) each Day after a date on or before which Section 6.1 states that a Seller's Conditions Precedent should occur and before the date that Seller has delivered Seller's CP

Confirmation Notice with respect to such Seller's Conditions Precedent (but not more than a maximum of ninety (90) days in the aggregate); provided that a Day meeting more than one of the above three (3) descriptions shall still be counted as just one Day for purposes of such extension.

4.2 Commercial Operation.

"Commercial Operation" means that:

(A) Commissioning has been completed and the Demonstrated Capacity has been determined by the Tests to be at least the Minimum Demonstrated Capacity of Solar Energy at the Point of Interconnection, as adjusted for the level of solar irradiation and ambient conditions at the time of the Commissioning Test;

(B) the Facility is fully operational and reliable and the Facility is fully interconnected, fully integrated, and synchronized with the Interconnection Provider's System, and is able to generate electric energy reliably in amounts expected by this Agreement and in accordance with all other terms and conditions hereof, evidence of which shall be Seller's responsibility to receive or obtain and deliver to Buyers;

(C) Buyers shall have received a certificate addressed to Buyers from a senior officer of Seller familiar with the Facility, attaching documentation and/or certifications from a registered professional engineer familiar with the Facility, stating:

(i) the conditions in clauses "(A)" and "(B)" above have been satisfied, and

(ii) all required Interconnection Facilities have been constructed, all required interconnection tests have been completed and the Facility is physically interconnected with the Interconnection Provider's System in conformance with the Interconnection Agreement and able to deliver energy consistent with the terms of this Agreement.

(D) Seller shall have demonstrated to Buyers' reasonable satisfaction that it can reliably transmit real time data and measurements from solar radiation meters to Buyers.

(E) Seller shall have furnished the Seller Credit Support.

(F) Seller shall have furnished certificates of insurance evidencing the coverages required by Article 16 have been obtained and submitted to Purchaser.

4.3 Test Energy. If Seller obtains Test Period Transmission Service, Seller shall coordinate the production and delivery of Test Energy with Buyers, including providing Buyers with prior notice of delivery as Buyers may reasonably request. Buyers shall cooperate with Seller to facilitate Testing of the Facility. If Seller obtains Test Period Transmission Service, Buyers shall accept delivery of Test Energy, provided that the

Facility is installed and interconnected in accordance with the Interconnection Agreement, and Buyers shall purchase such Test Energy delivered to the Point of Interconnection and beyond in accordance with Test Period Transmission Service at the Solar Energy Payment Rate.

ARTICLE 5
Delivery and Metering

5.1 Delivery Arrangements. Seller shall be responsible for all interconnection and transmission arrangements and costs required to deliver the Solar Energy Output and Test Energy from the Facility to Buyers at the Point of Interconnection at the required voltage. Buyers shall be responsible for all transmission arrangements and costs or charges, if any, imposed in connection with the delivery of Solar Energy Output at and from the Point of Interconnection, including transmission costs, transmission line losses, ancillary service arrangements and costs, control area or generator imbalance services, imbalance charges and associated penalties. Seller shall bear no responsibility related to delivery past the Point of Interconnection or any ancillary, control area or generator imbalance services required pursuant to Buyers' open access transmission tariff or any other transmission utility, regional transmission organization, NERC, the RE or any other entity. Seller shall diligently negotiate an Interconnection Agreement with the Interconnection Provider and post and maintain any and all security for payment and performance, if, when and for so long as required under the Interconnection Agreement.

5.2 Availability Reporting. Seller shall be responsible for providing accurate and timely updates on the current availability of the Facility to Buyers' SCC. Seller shall notify the SCC by telephone call (with confirmation in each case to follow by written notice or other form of documentation as agreed upon by both Parties) immediately upon discovering that the Facility is unable to deliver all or part of any scheduled quantity of Solar Energy Output due to a Forced Outage and, as soon as reasonably practicable following such discovery, shall notify the SCC in writing of its best estimate of the expected duration of such Forced Outage. Such estimate by Seller shall be based on the best information available to it. Should Seller expect any further changes in the duration of any such Forced Outage, it shall promptly notify the SCC of the same.

5.3 Electric Metering Devices. With respect to this Section 5.3, and notwithstanding the general applicability of the interpretive provisions of Section 1.2(B), the metering provisions of the Interconnection Agreement (including Article 7 thereof) are incorporated herein by reference and Buyers agree that Seller shall retain all of its rights thereunder without regard to any separateness of Buyers and the Interconnection Provider. Accordingly, electric metering shall be in compliance with the Interconnection Agreement. Seller will grant Buyers access to all metering data and other meter information, including testing, on same basis as available to Seller.

5.4 Interconnection Information. To the full extent authorized by FERC regulations and the FERC standards of conduct, Seller hereby authorizes Buyers to contact and obtain information concerning the Facility and Interconnection Facilities directly from the Interconnection Provider and, to the extent necessary, Seller shall provide written notice to the Interconnection Provider confirming such authorization.

ARTICLE 6
Conditions Precedent

6.1 Seller's Condition Precedent. This Section 6.1 describes certain conditions precedent to Seller's obligations under this PPA (collectively, the "Seller's Conditions Precedent"), each of which Seller shall pursue diligently with commercially reasonable efforts:

(A) Seller's obligations under this PPA are, subject to Section 6.3 below, conditioned upon the occurrence of each of Seller's Conditions Precedent described in this Section 6.1(A) (collectively the "Seller's Tier 1 CPs") on or before March 31, 2020:

(i) Seller shall have executed such easements, rights-of-way and other real estate contracts as may be necessary for the transmission line from the solar project to and including the Point of Interconnection;

(ii) Seller shall have received a Phase I environmental site assessment for the Site that is reasonably satisfactory to Seller;

(iii) Seller shall have received a preliminary title report with regard to the Site that does not include any third party encumbrances unacceptable to Seller;

(iv) Seller shall have received a private letter ruling or other assurances from the Kentucky Department of Revenue that it will use a cost approach, which is the net book value of the hard assets plus the fair market value of leased real and tangible property plus or minus cash working capital, to value the Facility during its expected life; and

(v) the Buyers' Tier 1 CP shall have been satisfied without any requirement to modify the terms of this Agreement and without any conditions unacceptable to Seller.

(B) Seller's obligations under this PPA are, subject to Section 6.3 below, conditioned upon the occurrence of Seller's Condition Precedent described in this Section 6.1(B) ("Seller's Tier 2 CP") on or before June 30, 2020:

(i) Seller shall have received all siting, zoning, planning commission, conditional use or other discretionary permits and other Governmental Approvals necessary for the construction and operation of the Facility, and such permits and Governmental Approvals have become final and non-appealable.

(C) Seller's obligations under this PPA are, subject to Section 6.3 below, conditioned upon the occurrence of each of Seller's Conditions Precedent described in this Section 6.1(C) (collectively the "Seller's Tier 3 CPs") on or before December 31, 2020; provided, however, that if the Seller's Tier 2 Confirmation Notice is issued after June 30, 2020, then, without affecting any termination right of either Party with respect to a delay in Seller's Tier 2 Confirmation Notice, the date by which Seller must satisfy Seller's Tier 3 CPs in Section 6.1(C)(i) shall be extended on a day-for-day basis, with such extended date treated for purposes of Section 4.1(B) as the date on or before which this Section 6.1 states that Seller's Tier 2 CP should occur:

(i) Seller shall have received approval for the Facility under the Kentucky Public Service Commission Electric Generation and Transmission Siting Board Energy, and such approval shall be final and non-appealable;

(ii) Seller shall have received a report from Buyers' ITO confirming that the aggregate non-refundable or non-creditable cost to Seller for interconnection, network, affected system and other upgrades is reasonably expected not to exceed [redacted];

(iii) Seller shall have received a report from Burns & McDonnell or such other engineering firm engaged by Seller confirming that the aggregate non-refundable or non-creditable cost to Seller for interconnection, network, affected system and other upgrades is reasonably expected not to exceed [redacted];

(iv) Buyers shall provide Seller written affirmation that: (A) Buyers have achieved Network Resource designation for the generating facility and has obtained appropriate Network Integration Transmission Service for the generating facility; and

(v) Seller shall have executed (i) a LGIA that allows for a Facility Capacity of at least [redacted] MWac and provides for a construction schedule that will allow the Seller to achieve the Required Commercial Operation Date or (ii) an Interim LGIA consistent with Section 3.3(B).

(D) Seller's obligations under this PPA are, subject to Section 6.3 below, conditioned upon the occurrence of Seller's Condition Precedent described in this Section 6.1(D) (the "Seller's Tier 4 CP") on or before March 31, 2021:

(i) Financial Closing has occurred.

6.2 Buyers' Condition Precedent. This Section 6.2 describes certain conditions precedent to Buyers' obligations under this PPA (collectively, the "Buyers' Conditions Precedent"), each of which Buyer shall pursue diligently with commercially reasonable efforts:

(A) Buyers obligations under this PPA are, subject to Section 6.3 below, conditioned upon the occurrence of the Buyers' Condition Precedent described in this Section 6.2(A) (the "Buyers' Tier 1 CP") on or before March 31, 2020:

(i) Buyers shall have received all permits and approvals, and shall have satisfied all other requirements under Applicable Law, including the Commission Approvals.

(B) Buyers obligations under this PPA are, subject to Section 6.3 below, conditioned upon the occurrence of each of the Buyers' Conditions Precedent described in this Section 6.2(B) (collectively, the "Buyers' Tier 3 CPs") on or before December 31, 2020:

(i) Interconnection Provider shall have qualified the Facility as a Designated Network Resource and Buyers are capable of scheduling the entire Facility Capacity as a Designated Network Resource; and

(ii) Buyers shall have secured unconditional firm network transmission service from the Point of Interconnection to Buyer's load for the Term.

6.3 Failure of Condition Precedent.

(A) Tier 1 CPs. The Tier 1 Seller's CPs and Tier 1 Buyers' CP (collectively the "Tier 1 CPs") shall be deemed satisfied upon (i) delivery by Seller to Buyers of a written notice stating that Seller has achieved or waived all Tier 1 Seller's CPs and that Seller does not object to any conditions of the approvals on which the Tier 1 Buyers' CP is based (the "Seller's Tier 1 CP Confirmation Notice"); and (ii) delivery by Buyers to Seller of a written notice stating that Buyers have achieved or waived all Tier 1 Buyers' CPs and that Buyer does not object to any conditions of the approvals on which the Tier 1 Buyers' CP is based (the "Buyers' Tier 1 CP Confirmation Notice"). If the Seller's Tier 1 CP Confirmation Notice and/or the Buyers' Tier 1 CP Confirmation Notice are not delivered by March 31, 2020, either Party may deliver a termination notice to the other Party (a "Tier 1 CP Termination Notice") with such termination effective on the date sixty (60) days following such Tier 1 CP Termination Notice unless the Party that did not deliver the CP Confirmation Notice that is the subject of such Tier 1 CP Termination Notice by March 31, 2020 delivers such CP Confirmation Notice before the end of such sixty (60) day period, in which case the Tier 1 CP Termination Notice shall be automatically rescinded and this Agreement shall continue in full force and effect. Either Party may provide a Tier 1 CP Termination Notice with immediate effect at any time prior

March 31, 2020 if it reasonably determines that such Party's Tier 1 CPs will not be achieved by March 31, 2020.

(B) Tier 2 CPs. The Tier 2 Seller's CP shall be deemed satisfied upon delivery by Seller to Buyers of a written notice stating that Seller has achieved or waived all Tier 2 Seller's CPs (the "Seller's Tier 2 CP Confirmation Notice"). If the Seller's Tier 2 CP Confirmation Notice is not delivered by June 30, 2020, either Party deliver a termination notice to the other Party (a "Tier 2 CP Termination Notice") with such termination effective on the date sixty (60) days following such Tier 2 CP Termination Notice unless, before the expiration of such sixty (60) day period, Seller delivers the Seller's Tier 2 CP Confirmation Notice, in which case the Tier 2 CP Termination Notice shall be automatically rescinded and this Agreement shall continue in full force and effect. Seller may provide a Tier 2 CP Termination Notice with immediate effect at any time prior June 30, 2020 if it reasonably determines that any Tier 2 Seller's CPs will not be achieved by June 30, 2020.

(C) Tier 3 CPs. The Tier 3 Seller's CPs and Tier 3 Buyers' CPs (collectively the "Tier 3 CPs") shall be deemed satisfied upon (i) delivery by Seller to Buyers of a written notice stating that Seller has achieved or waived all Tier 3 Seller's CPs (the "Seller's Tier 3 CP Confirmation Notice") and (ii) delivery by Buyers to Seller of a written notice stating that Buyers have achieved or waived all Tier 3 Buyers' CPs (the "Buyers Tier 3 CP Confirmation Notice"). Subject to any extension as described in Section 6.1(C), if the Seller's Tier 3 CP Confirmation Notice and/or the Buyers' Tier 3 CP Confirmation Notice are not delivered by December 31, 2020, either Party may deliver a termination notice to the other Party (a "Tier 3 CP Termination Notice") with such termination effective on the date sixty (60) days following such Tier 3 CP Termination notice unless the Party that did not deliver the CP Confirmation Notice that is the subject of such Tier 3 CP Termination Notice by December 31, 2020 delivers such CP Confirmation Notice before the end of such sixty (60) day period, in which case the Tier 3 CP Termination Notice shall be automatically rescinded and this Agreement shall continue in full force and effect. Either Party may provide a Tier 3 CP Termination Notice with immediate effect at any time prior December 31, 2020 if it reasonably determines that such Party's Tier 3 CPs will not be achieved by December 31, 2020.

(D) Tier 4 CPs. The Tier 4 Seller's CP shall be deemed satisfied upon delivery by Seller to Buyers of a written notice stating that Seller has achieved or waived all Tier 4 Seller's CPs (the "Seller's Tier 4 CP Confirmation Notice"). If the Seller's Tier 4 CP Confirmation Notice is not delivered by March 31, 2021, either Party may deliver a termination notice to the other Party (a "Tier 4 CP Termination Notice") with such termination effective on the date sixty (60) days following such Tier 4 CP Termination notice unless, before the expiration of such sixty (60) day period, Seller delivers the Seller's Tier 4 CP Confirmation Notice, in which case the Tier 4 CP Termination Notice shall be automatically rescinded and this Agreement shall continue in full force and effect. Seller may provide a Tier 4 CP Termination Notice with immediate effect at any time prior December 31, 2021 if it reasonably determines that any Tier 4 Seller's CPs will not be achieved by December 31, 2021.

(E) Upon the effectiveness of any termination as provided in this Section 6.3, this Agreement shall terminate without any liability for any Party.

ARTICLE 7
Sale and Purchase of Solar Energy Output and Renewable Energy Benefits

7.1 Sale and Purchase of Solar Energy Output and Capacity.

(A) Beginning on the Commercial Operation Date, Seller shall generate from the Facility, deliver to the Point of Interconnection, and sell to Buyers all the Solar Energy Output not exceeding the Facility Capacity and all of the Renewable Energy Benefits produced by the Facility in connection with such Solar Energy Output, LG&E shall purchase the LG&E Percentage of such Solar Energy Output and Renewable Energy Benefits, and KU shall purchase the KU Percentage of such Solar Energy Output and Renewable Energy Benefits, all as provided in Section 8.1.

(B) As between Seller and Buyers, Seller shall be in control of the Solar Energy Output and Test Energy from the Facility up to and until delivery and receipt at the Point of Interconnection and Buyers shall be in control of such energy from and after delivery and receipt at the Point of Interconnection. Title and risk of loss related to the Solar Energy Output and Test Energy shall transfer from Seller to Buyers at the Point of Interconnection.

(C) Ownership by Buyers of Renewable Energy Benefits as set forth in Section 7.1(A) shall be for the entire Term of this PPA, including any Renewable Energy Benefits that are reserved or "banked" throughout the Term of this PPA, but not used, sold, assigned or otherwise transferred during the Term of this PPA. Each Buyer may, to the extent permitted by Applicable Law and this PPA, assign its rights, title and interest in and to any Renewable Energy Benefits obtained under Section 7.1(A) (but not any payment obligation) to one or more third parties under any transaction permitted by Applicable Law. Any financial or other compensation received by Buyers from the disposition of Renewable Energy Benefits Reporting Rights held by Buyers as set forth in Section 7.1(A) shall inure solely to the benefit of Buyers.

(D) Tax Credits in effect on the date of this PPA or arising hereafter shall be accrue solely to the benefit of Seller.

(E) Seller and Buyers shall execute all documents and instruments necessary to effect the transfer of the Renewable Energy Benefits to Buyers or their respective designees, including those required for compliance with all Applicable Laws, including a Renewable Energy Law, if enacted, and all rules and regulations established by any Person for the issuance and tracking of RECs, and the PSC. Without limiting the generality of the foregoing, Seller shall, within a reasonable time after the effective date of any Renewable Energy Law, obtain for the Facility such designation as is required under such Renewable Energy Law for the transfer of the Renewable Energy Benefits to

Buyers or their respective designees in accordance with such Renewable Energy Law; provided that Seller shall not be required to incur costs in obtaining such designation to the extent such costs are materially greater than the costs of obtaining a comparable designation under Renewable Energy Laws in other states in general.

(F) Subject to Section 7.1(G), from time to time, the Buyers may, by 30 days' written notice to Seller, change the LG&E Percentage and KU Percentage, subject to the following conditions:

(1) the sum of the LG&E Percentage and the KU Percentage following such change shall be equal to one hundred percent (100 %);

(2) the Buyer for which the percentage will increase is not subject to a Credit Event; and

(3) the Buyers have obtained any and all Governmental Approvals required for such change.

(G) A change requested under Section 7.1(F) that satisfies the conditions stated in Section 7.1(F) shall become effective on the first Day of the Month following the month in which the thirtieth (30^{th}) Day following Buyers' notice falls, at which time this PPA shall be deemed amended with respect to the LG&E Percentage and KU Percentage.

7.2 Scheduling.

(A) Scheduling shall be on a "must-take" basis, except to the extent that the Solar Energy Output of the Facility is reduced as a result of Forced Outages, Scheduled Maintenance Outages, Additional Maintenance Outages, Force Majeure events and Emergency Conditions. At least thirty (30) Days prior to the anticipated Commercial Operation Date, Seller shall provide Buyers with a good faith estimate of the quantity of Solar Energy Output that it expects to generate for the remainder of that Year and the following Year if Commercial Operation Date is after October 1 in the Year that the Commercial Operation Date is achieved. By October 1 of each succeeding Year, Seller shall provide Buyers with a good faith estimate of the hourly quantities of Solar Energy Output that Seller expects to generate in the following Year (the "Projected Schedule").

(B) Seller shall provide to Buyers its good faith, non-binding estimates of the daily quantity (by hour) of Solar Energy Output to be delivered by Seller to the Point of Interconnection for the following three (3) Month period by 4:00 p.m. EST on the date falling at least three (3) Days prior to the beginning of that Month.

(C) If, at any time following submission of a good faith estimate as described in Section 7.2(B), Seller becomes aware of any change that materially alters the values previously provided to Buyers, Seller shall promptly notify Buyers of such change or predicted change.

7.3 No Sale to Third Parties. Except as provided in Section 8.2, all of the Solar Energy Output and Renewable Energy Benefits shall be dedicated exclusively to Buyers for so long as this Agreement is in force and effect. Seller shall not (a) sell, divert, grant, transfer or assign any Solar Energy Output, Renewable Energy Benefits, or Capacity Rights to any Person other than Buyer, (b) provide Buyer with any such items from any source other than the Facility or (c) divert, redirect or make available the Facility or any resource therefrom to another generating facility or any third party. The Parties agree that remedies at Law may be inadequate in the event of a breach of this Section 7.3, and Seller agrees that Buyer shall be entitled to seek without proof of actual damages, temporary, preliminary and permanent injunctive relief from any Governmental Authority of competent jurisdiction restraining Seller from committing or continuing any breach of this Section 7.3.

ARTICLE 8
Payment Calculations

8.1 Payments to Seller.

(A) Except as otherwise provided in this PPA, each Buyer shall pay Seller a monthly payment due and payable in each Monthly Billing Period in accordance with the invoicing procedures set forth in Section 9.1 equal to the following amount (the "Solar Energy Payment"): the sum, over all hours of the Monthly Billing Period, of the LG&E Percentage or the KU Percentage (as applicable), multiplied by the product of: (i) the Solar Energy Payment Rate; and (ii) the sum of Solar Energy Output (MWh) delivered to the Point of Interconnection from the Facility during that hour plus all Curtailed Energy during that hour; provided, however, if the aggregate Solar Energy Output during a Year includes Excess Solar Energy, then the portion of any Solar Energy Payment attributable to such Excess Solar Energy shall be determined as set forth above in this Section 8.1(A), but using the Excess Solar Energy Payment Rate in place of the Solar Energy Payment Rate.

(B) Test Energy Payment. Subject to Section 4.3, each Buyer shall pay Seller for Test Energy generated prior to the Commercial Operation Date by making a monthly payment due and payable in each Monthly Billing Period in accordance with the invoicing procedures set forth in Section 9.1, equal to the product of the LG&E Percentage or the KU Percentage (as applicable) of: (a) the Solar Energy Payment Rate; and (b) the amount of Test Energy (MWh) delivered during that Month.

8.2 Curtailed Energy.

(A) If (i) Seller cannot deliver Solar Energy Output because of a Seller Delivery Excuse; or (ii) delivery of Solar Energy Output is curtailed by a Buyer other than as a result of an Emergency Condition, then, if permitted pursuant to Applicable Law, Seller may offer such Solar Energy Output ("Curtailed Energy") and all Renewable Energy Benefits that would have been produced by the Facility had its generation not been so curtailed ("Curtailed Renewable Energy Benefits") to third-parties as may be interested and able to purchase such Solar Energy Output. If Seller sells any Curtailed Energy or

Curtailed Renewable Energy Benefits then the amount payable by Buyers pursuant to Section 8.1(A) shall be reduced by the net revenue received by Seller pursuant to such sale. Seller shall not be in default hereunder if it does not sell (or offer for sale) any Curtailed Energy or Curtailed Renewable Energy Benefits.

(B) The Parties shall determine the quantity of Curtailed Energy and Curtailed Renewable Energy Benefits by taking into account the following: (1) during such periods, the actual levels of solar irradiation and ambient conditions as measured at the Site, or if such data is not available, using other available data determined using Prudent Industry Practices, (2) the incremental energy that would have been produced based on ambient conditions at the Site, and (3) the actual availability of the Facility.

8.3 Availability Guaranty.

(A) On or before sixty (60) days after the Commercial Operation Date, Seller shall provide Buyers with the Production Model. The Production Model shall be used to calculate the Expected Amount. If a Party believes that the Production Model is inaccurate, such Party may propose an adjustment to the Production Model, and if the Parties are not able to resolve such issues within sixty (60) Days of the initial notice of the suspected inaccuracy, then the Parties shall submit such dispute to an independent engineering company with experience with solar production models to resolve such issue.

(B) Seller guarantees that the actual Availability of the Facility shall be at least [redacted] percent ([redacted]%) (the "Guaranteed Availability") measured over each Availability Day. From time to time, Buyers may, if Buyers' data indicates that an Availability Unsatisfactory Day has occurred, request that Seller provide, and Seller shall provide, a report of the Expected Amount determined using the Production Model; provided that, outside of any Availability LD Cure Period or Availability Default Period, Buyers shall be limited to making such requests no more than five (5) times in any Month. If Seller does not achieve the Guaranteed Availability for any Availability Day, Buyers may provide Seller with written notice that the Facility did not achieve the Guaranteed Availability (an "Availability Underperformance Notice"). If an Availability Underperformance Notice is delivered, then: (i) if an Availability Satisfactory Day occurs during the Availability LD Cure Period, then Seller shall not be in default hereunder; and (ii) if an Availability Satisfactory Day does not occur during the Availability LD Cure Period, Seller shall, for each Availability Day occurring after the Availability LD Cure Period and before the earlier of (A) the occurrence of an Availability Satisfactory Day or (B) the termination or expiration of this PPA, pay liquidated damages to Buyers (pro-rata to each Buyer in proportion to the LG&E Percentage or KU Percentage, as applicable) equal to: (1) the Guaranteed Availability minus the actual Availability on such Availability Day; multiplied by (2) the Expected Amount during such Availability Day; multiplied by (3) the LD Monetary Factor for such Availability Day determined in accordance with Section 8.3(C).

(C) The "LD Monetary Factor" for an Availability Day is equal to the lesser of (i) [redacted] or (ii) the greater of (1) the LD Avoided Cost Input for such Availability Day or (2) the LD REC Input for such Availability Day. If items (1) and (2) in the preceding sentence are the same amount, item (ii) shall be such amount. If items (i) and (ii) are equal, the LD Monetary Factor shall be [redacted].

(D) In the event liquidated damages become due under Section 8.3(B) Buyers shall, no more frequently than once per calendar month, calculate and issue a statement to Seller for the amount due Buyers for the amount due under Section 8.3(B). Seller shall pay the amounts due under each such invoice within thirty (30) Days of receipt thereof.

(E) Each Party agrees and acknowledges that (i) the damages that Buyers would incur due to the Facility's failure to achieve the Guaranteed Availability would be difficult or impossible to predict with certainty, (ii) the amount contemplated by this provision are a fair and reasonable calculation of such damages, and (iii) without limiting remedies with respect to an Event of Default, the required payment by Seller under this Section 8.3 shall be Buyers' sole remedy for the matters covered by this Section 8.3. Occurrence where the actual Availability is less than the Guaranteed Availability shall not be an Event of Default, except as provided in Section 12.1(C)(vii).

8.4 Payment Support Requirement. Neither Party shall initiate any action before any Governmental Authority to deny recovery of payments under this PPA, and each Party shall use its best efforts to defend all terms and conditions of this PPA consistent with Applicable Law.

8.5 Survival on Termination. The provisions of this Article 8 shall survive the repudiation, termination or expiration of this PPA for so long as may be necessary to give effect to any outstanding payment obligations of the Parties due and payable prior to any such repudiation, termination or expiration.

ARTICLE 9
Billing and Payment Procedures

9.1 Statements and Payment of Electricity Payments.

(A) Seller shall read or have read on its behalf the Electric Metering Devices at the Points of Delivery at 11:59 p.m. EST on the last Day of each Month, unless otherwise mutually agreed by the Parties.

(B) On or before the tenth Day of each Month following the Month in which the Commercial Operation Date occurs, Seller shall prepare an invoice showing the Solar Energy Payment payable by each Buyer pursuant to Article 8 of this PPA (in Dollars) payable to Seller for the preceding Month. Each such invoice shall show information and calculations, in reasonable detail. Each Buyer shall pay Seller such invoiced amounts within thirty (30) Days of the date of delivery of such invoice.

(C) Subject to Section 4.3, beginning with the first Month following the Month in which any part of the Facility has been Commissioned until an invoice is required to be prepared pursuant to clause (B) above, Seller shall prepare an invoice showing the charges for Test Energy and Renewable Energy Benefits payable to Seller for the preceding Month. Each Buyer shall pay Seller such invoiced amounts within fifteen (15) Days of the date of such invoice.

(D) Each Buyer shall, subject to Sections 9.5 and 9.8, pay all invoices on or before the due date therein specified consistent with (C) above. If a Buyer should dispute a portion of the charges set forth on any invoice, it shall nonetheless pay all amounts not in dispute by the applicable due date.

(E) If any date on which any payment by Buyers would otherwise have been due is not a Business Day, then Buyers shall make such payment on the Business Day that immediately follows such payment date.

(F) In the event a Buyer directs Seller in writing to treat the other Buyer as the agent for billing purposes of the Buyer providing such direction, Seller shall, except as otherwise provided in this Section 9.1(F), direct its invoices under this PPA to the Buyer being identified as the agent of the other Buyer. Seller may request written confirmation of such an arrangement from the Buyer being designated as agent, and may condition such invoicing arrangement on receiving such confirmation. In the event one or both Buyers experience a Credit Event, Seller may thereafter decline to invoice either Buyer as agent for the other Buyer. The designation of a Buyer as the agent of the other Buyer shall have no effect on the obligations of the Buyers hereunder, including the LG&E Percentage or KU Percentage or the obligation to make payments due hereunder.

9.2 Miscellaneous Payments. Any amounts due to either Seller or Buyers under this PPA, other than those specified in Section 9.1 above, shall be paid within thirty (30) Days following receipt by the other Party of an itemized invoice from the Party to whom such amounts are due setting forth, in reasonable detail, the basis for such payment. If either Party is billed or credited for any charges, costs, fees, penalties, credits or other amounts properly payable by the other Party pursuant to the terms of this Agreement, the Party receiving such invoice shall deliver such invoice to the other Party and such other Party shall pay such invoice within thirty (30) days after receipt by the receiving Party.

9.3 Currency and Method of Payment. Notwithstanding anything contained in this PPA, all payments to be made by either Seller or Buyers under this PPA shall be made in Dollars in immediately available cleared funds by automated clearing house (ACH) or wire transfer into the relevant account specified in this PPA or, if no account is specified, into the account designated by the receiving Party by written notice consistent with Article 13 below.

9.4 Interest. Except where payment is the subject of a bona fide dispute (in which case it shall be treated under Section 9.5 below), if any payment due from Buyers to Seller or from Seller to Buyers under this PPA is not paid when due, then, in addition to such unpaid amount, interest shall be due and payable thereon. Applicable interest shall be the Prime Rate, and shall continue to accrue from the date on which Contractor provided Buyers with notice that such payment became overdue to and until the date such payment is made in full (both dates inclusive).

9.5 Disputed Items.

(A) Either Party (the "Disputing Party") may dispute in good faith the accuracy of a reading of the Electric Metering Devices and/or the accuracy of an invoice. Where a reading or bill is the subject of a dispute in good faith, the Disputing Party shall give written notice to the other Party within ten (10) Days after the delivery of the invoice or statement by the other Party, together with details of its reasons for such dispute. The Disputing Party shall make payment of any undisputed amounts to the other Party by the due date for payment specified in such invoice. Any amount or adjustment with respect to a meter reading subsequently agreed to by the Parties or determined to be due shall be made (in each case in settlement of a dispute) by a credit or additional charge on the next bill rendered (as the case may be).

(B) All amounts paid as a result of the settlement of a dispute shall, unless the terms of such settlement provide otherwise, be paid with interest thereon at the Prime Rate from the Day on which such payment originally fell due to and until the date such payment is made in full (both dates inclusive).

9.6 Statement Errors. In the event that either Party becomes aware of any error in any statement within one (1) year of the date of a statement, such Party shall, immediately upon discovery of the error, notify in writing the other Party of such error and shall rectify such error (whether such error was in the form of an underpayment or overpayment) within thirty (30) Days of such notification. Provided that the other Party is satisfied (in its sole and reasonable discretion) that the aforementioned notification requirements have been complied with in good faith by the Party who has made the error, no interest shall be payable in respect of any amount that was erroneously overpaid or underpaid. No adjustment to a billing statement shall be made if notice of an error in such statement is not provided within one (1) year of the date of such statement.

9.7 Taxes.

(A) All Solar Energy Output delivered by Seller to Buyers hereunder is on a wholesale basis. Buyers may use the Solar Energy Output for their own consumption or resell it to third parties. Buyers shall obtain and provide Seller with any certificates required by any Governmental Authority, or otherwise reasonably requested by Seller, to evidence that the deliveries of Solar Energy Output hereunder are sales for resale.

(B) Seller shall not be obligated to pay or reimburse Buyers for Taxes imposed on or measured by Buyers' overall revenues or income. Each Buyer shall be responsible for the payment of, and no amount payable by Seller to a Buyer shall be subject to adjustment for, Taxes imposed on such Buyer and its property.

(C) If a Party is required to remit or pay Taxes that are the other Party's responsibility hereunder, such Party shall promptly reimburse the other for such Taxes.

(D) The Parties shall provide each other, upon written request, with copies of any documentation that may be reasonably necessary in the ordinary course of any inter-governmental, state, local, municipal or other political subdivision tax audit inquiry or investigation.

(E) Consistent with Applicable Law, the Parties shall cooperate to minimize Taxes; however, no Party shall be obligated to incur any material financial burden to reduce Taxes for which the other Party is responsible hereunder.

9.8 Set-Off and Payment Adjustments. All payments between the Parties under this PPA shall be made free of any restriction or condition and without deduction or withholding on account of any other amount, whether by way of set-off or otherwise. Payments to be made under this PPA shall, for a period of not longer than two (2) years, remain subject to adjustment based on billing adjustments due to error or omission by either Party, provided that such adjustments have been agreed to between the Parties or resolved in accordance with the provisions of Section 20.14 hereof.

9.9 Security Deposit. In the event a Buyer fails to make (directly or through the other Buyer) timely payment of two (2) or more Monthly invoices of Seller in any twelve (12) month period, such Buyer shall provide Seller (following Seller's invoice for such amount) with a cash security deposit from such Buyer equal to the average amount of the previous twelve (12) monthly invoices to such Buyer, and Seller shall retain such security deposit until such time as such Buyer has timely paid twelve (12) consecutive Monthly invoices, during which time Seller may apply such funds towards any invoice that is not paid by such Buyer when due.

9.10 Survival on Termination. The provisions of this Article 9 shall survive the repudiation, termination or expiration of this PPA for so long as may be necessary to give effect to any outstanding payment obligations of the Parties that became due and payable prior to any such repudiation, termination or expiration.

ARTICLE 10
Operations and Maintenance

10.1 Construction of the Facility.

(A) Starting on the date that falls one Month after the earlier of the date on which construction of the Facility commences or the date upon which a notice to proceed under the EPC Contract is given in accordance with the terms of the EPC Contract and, thereafter, at Monthly intervals, Seller shall report to Buyers on the construction of the Facility during the previous Month and shall provide progress reports and an updated completion schedule for the Facility. Such Monthly reports shall provide a schedule showing items completed and to be completed and a best estimate time-frame within which Seller expects its contractor to complete such non-completed work. None of the foregoing shall be deemed to be in lieu of, or in substitution for, the general record and reporting obligations attendant to Seller in accordance with Article 13 hereof.

(B) Other than the rights and obligations of Buyers specified in this PPA and any documents ancillary hereto, neither this PPA nor any such ancillary document shall be interpreted to create in favor of Buyers, and each Buyer specifically disclaims, any right, title or interest in any part of the Facility.

10.2 Commissioning Tests.

(A) Seller shall coordinate testing plans with Buyers by providing a Testing plan at least thirty (30) days prior to the first anticipated Test Date, updates to such Testing plan on a weekly basis, and at least forty-eight (48) hours prior notice of the actual Test Date and of the proposed Tests scheduled relating to the Commissioning of the Facility, which tests shall include insulation resistance (Megger) testing for all MV AC conductors, DC feeders, and Homeruns in accordance with NETA ATS 2013 7.3.3 ("Commissioning Tests"). Representatives of each Buyer shall have the right to be present at all such Testing. Seller shall promptly notify Buyers of any changes to the Test Date or the date of any Commissioning Tests relating to the Facility in order that Buyers may arrange for their respective representatives to attend.

(B) The results of Commissioning Tests, including the use of testing consistent with standard ASTM E2848-13(2018) (Standard Test Method for Reporting Photovoltaic Non-Concentrator System Performance), shall determine the Facility's Demonstrated Capacity. Seller may conduct multiple Commissioning Tests to determine the highest Demonstrated Capacity.

(C) Subject to Section 4.3, Test Energy shall be delivered by Seller for Buyers at the Point of Interconnection, and Buyers shall purchase such Solar Energy Output as set forth in Section 8.1(B).

10.3 Maintenance of the Facility. Seller shall at all times maintain or cause to be maintained all Facility equipment in accordance with manufacturers' recommendations and Prudent Industry Practices and otherwise in accordance with this PPA or Interconnection Agreement.

10.4 Scheduled Maintenance.

(A) Three (3) Months prior to the Commercial Operation Date and, thereafter, by October 1 of each Year, Seller shall deliver to Buyers and SCC the Projected Schedule for the Facility for the subsequent annual period, including Scheduled Maintenance Outages. Seller shall take manufacturers' recommendations and Prudent Industry Practices into account when establishing the proposed schedule for Scheduled Maintenance Outages, which schedule shall correspond with the Projected Schedule. Seller shall use commercially reasonable efforts to not schedule Scheduled Maintenance Outages and/or Additional Maintenance Outages during the daytime hours during the Months of June, July, August, or September (the "Non-Scheduled Maintenance Period").

(B) Within thirty (30) Days of receiving the proposed schedule for Scheduled Maintenance Outages from Seller, Buyers may propose amendments thereto.

Seller shall not unreasonably withhold its consent to such proposed amendments, provided that, it shall not be unreasonable for Seller to withhold its consent to any such proposed amendments that would be contrary to Prudent Industry Practices.

(C) Seller shall be entitled to change any Scheduled Maintenance Outages for the then current Year upon notice to Buyers and SCC. Seller shall not unreasonably refuse to change the schedule of Scheduled Maintenance Outages if requested to do so by Buyers upon not less than fourteen (14) Days' prior notice, provided that any such change would not be contrary to Prudent Industry Practices or cause Seller to incur any material costs.

(D) Any maintenance outages that do not correspond to the descriptions contained in clauses (A)-(C) of this Section 10.4 shall be deemed to be Additional Maintenance Outages under Section 10.5.

10.5 <u>Additional Maintenance Outages</u>. As the need arises for Seller to conduct further maintenance on the Facility during which the Facility is shut down or its output reduced in addition to that conducted pursuant to Section 10.4 hereof ("Additional Maintenance Outages"), Seller shall notify Buyers of such required maintenance, together with proposed dates for carrying out such additional maintenance and the estimated duration of the work to be carried out. Unless deferral of such maintenance would cause an Emergency Condition, Seller shall prepare a schedule of such Additional Maintenance Outages based on Prudent Industry Practices taking into account the reasonable requests of Buyers to the extent reasonably possible. Seller shall use Prudent Industry Practices to avoid Additional Maintenance Outages during the Non-Scheduled Maintenance Period. Notwithstanding the foregoing, Additional Maintenance Outages that consist of washing photovoltaic panels to improve production of the Facility may be performed by Seller upon written notice to Buyers.

10.6 <u>Access to and Inspection of Facility</u>.

(A) Seller shall provide Buyers and their authorized agents, employees and inspectors with reasonable access to the Facility for the purposes of inspecting the Facility consistent with Prudent Industry Practices. Each Buyer acknowledges that such access does not provide Buyers with the right to direct or modify the operation of the Facility in any way. Buyers shall abide by Seller's generally-applied safety procedures and rules while visiting the Site.

(B) No inspections of the Facility, whether by a Buyer or otherwise, shall relieve Seller of its obligation to maintain the Facility and operate the same in accordance with Prudent Industry Practices and Applicable Laws. In no event shall any statement, representation, or lack thereof by a Buyer, either express or implied, relieve Seller of its exclusive responsibility for the Facility. Any inspection of Seller's property or equipment by a Buyer or any review by a Buyer or consent by a Buyer to Seller's plans, shall not be construed as endorsing the design, fitness or operation of the Facility equipment nor as a warranty or guarantee.

ARTICLE 11
Security

11.1 Seller Security. Within ten (10) Business Days after the satisfaction of the Tier 1 Buyers' CP, Seller shall cause the Seller Credit Support to be provided to Buyers. The "Seller Credit Support" shall be maintained throughout the term of this Agreement and take the form of (i) a guaranty from an Affiliate of Seller with an Investment Grade Rating or (ii) a Surety Bond from a major U.S. commercial bank or surety company or the U.S. branch of a foreign bank or surety company with total assets of at least [redacted], and such bank or surety company having a long term senior debt obligations of which are rated "BBB+" or better by Standard & Poor's (S&P) or "Baa1" or better by Moody's (or an equivalent rating from an equivalent rating agency as may be approved by Buyers. The Seller Credit Support shall be in an aggregate amount of [redacted]. Seller may change the form of Seller Credit Support from time to time so long as such credit support is reasonably acceptable to Buyers and there is no lapse in Seller Credit Support. The form of Seller Credit Support shall be substantially in the form of Exhibit E (Guaranty) or one of the two forms attached as Exhibit C (Surety Bond). If the Seller Credit Support is in the form of a surety bond, Seller will furnish the audited financial statements of the surety company for the end of every fiscal year of such surety company. If the total assets of the surety company falls below [redacted] asset requirement or the general long-term senior unsecured debt obligation rating falls below BBB+ as rated by S&P Global Ratings, or Baa1 as rated by Moody's Investors Service, Inc. or a comparable rating by an entity succeeding to the functions and business of such rating agencies, then Buyer shall provide notice to Seller that it is in breach of its obligations under this Section 11.1, and Seller shall have ninety (90) days from notice to comply with this Section 11.1.

11.2 Effect of Security. Nothing in this Article 11, any security agreement or any surety bond is intended, or shall be deemed or construed to, in any way limit or modify any obligation or agreement of or recourse to the Parties hereunder.

ARTICLE 12
Default and Remedies

12.1 Events of Default of Seller.

(A) Any of the following shall constitute an Event of Default of Seller upon its occurrence and no cure period shall be applicable:

(i) Seller's dissolution or liquidation;

(ii) Seller's filing of a petition in voluntary bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any state, or Seller voluntarily taking advantage of any such law by answer or otherwise;

(iii) The sale of Solar Energy Output by Seller to a third party, or diversion by Seller for any use of Solar Energy Output committed to Buyers by Seller other than in mitigation of damages for any breach by a Buyer of this PPA or during any period during which a Buyer does not take delivery of Solar Energy Output as described herein; and.

(iv) Seller's failure to establish and maintain the Seller Credit Support in accordance with Article 11.

(B) Seller's failure to make any payment due hereunder (subject to Seller's rights with respect to disputed payments under Article 9) that is not cured within thirty (30) Days after Seller's receipt of notice of such nonpayment from Buyers shall constitute an Event of Default of Seller.

(C) Any of the following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within sixty (60) Days after the date of written notice from Buyers to Seller and the Financing Parties:

(i) Seller's Abandonment of the Facility;

(ii) Seller's assignment of this PPA except as permitted in accordance with Article 19;

(iii) Any representation or warranty made by Seller in this PPA shall prove to have been false or misleading in any material respect when made and such misrepresentation or breach of warranty would reasonably be expected to result in a material adverse impact on Buyers;

(iv) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against Seller as debtor that could materially impact Seller's ability to perform its obligations hereunder; provided, however, that Seller does not obtain a stay or dismissal of the filing within the cure period;

(v) Seller's failure to comply with any other material obligation of Seller under this PPA, which would result in a material adverse impact on one or both Buyers;

(vi) Seller's failure to comply with Section 10.3; or

(vii) An Availability Satisfactory Day does not occur within an Availability Default Period.

(D) The following shall constitute an Event of Default of Seller upon its occurrence but shall be subject to cure within 90 Days after the date of written notice from

Buyers to Seller: the Commercial Operation Date is not achieved by Required Commercial Operation Date (as extended under Section 4.1(B)).

(E) It shall not be an Event of Default of Seller hereunder if Seller does not produce a specified amount of Solar Energy Output or Renewable Energy Benefits.

(F) Seller shall not be liable for or deemed in breach of this Agreement to the extent the performance of its obligations under this PPA is delayed or prevented by a Seller Delivery Excuse.

12.2 Events of Default of Buyers.

(A) Any of the following shall constitute an Event of Default of a Buyer upon its occurrence, and no cure period shall be applicable:

(i) Such Buyer's dissolution or liquidation provided that division of such Buyer into multiple entities shall not constitute dissolution or liquidation;

(ii) Such Buyer's assignment of this PPA or any of its rights hereunder for the benefit of creditors; or

(iii) Such Buyer's filing of a voluntary petition in bankruptcy or insolvency or for reorganization or arrangement under the bankruptcy laws of the United States or under any insolvency law of any State, or such Buyer voluntarily taking advantage of any such law by answer or otherwise.

(B) Such Buyer's failure to make any payment due hereunder (subject to Buyer's rights with respect to disputed payments under Article 9) that is not cured within thirty (30) Days of the date on which such payment is due shall constitute an Event of Default of such Buyer.

(C) Any of the following shall constitute an Event of Default of a Buyer upon its occurrence but shall be subject to cure within sixty (60) Days after the date of written notice from Seller to such Buyer:

(i) The filing of an involuntary case in bankruptcy or any proceeding under any other insolvency law against such Buyer; provided, however, that such Buyer does not obtain a stay or dismissal of the filing within the cure period;

(ii) Such Buyer's assignment of this PPA, except as permitted in accordance with Article 19;

(iii) Any representation or warranty made by such Buyer in this PPA shall prove to have been false or misleading in any material respect when made and such misrepresentation or breach of warranty is reasonably expected to result in a material adverse impact on Seller; or

(iv) Such Buyer's failure to comply with any other material obligation of such Buyer under this PPA, which would result in a material adverse impact on Seller.

12.3 Damages Prior to Termination. Upon the occurrence of an Event of Default, and subject in each case to the limitation on damages set forth in Section 12.6, the non-defaulting Party shall have the right to suspend its performance of this Agreement and collect damages accruing prior to the termination of this PPA from the defaulting Party, and the payment of any such damages accruing prior to the cure of an Event of Default shall constitute an element of any respective cure. If a Buyer has committed an Event of Default, then Seller may suspend its performance hereunder and, if allowed by Applicable Law, sell the Solar Energy Output and Renewable Energy Benefits to a third party in an effort to mitigate the damages payable by Buyer, or may continue to deliver Solar Energy Output and Renewable Energy Benefits to such Buyer.

12.4 Termination.

(A) Upon the occurrence of an Event of Default that is not cured within the applicable cure period, if any, the non-defaulting Party shall have the right to declare a date, which shall be between fifteen (15) and thirty (30) Days after the notice thereof, upon which this PPA shall terminate (the "Early Termination Date"); provided, however, that if a Buyer Event of Default has occurred, then Seller may terminate this Agreement with regard to only such Buyer. Neither Party shall have the right to terminate this PPA except as provided for upon the occurrence of an Event of Default as described above or as may be otherwise explicitly provided for in this PPA.

(B) Upon the termination of this PPA under this Section 12.4, the non-defaulting Party shall be entitled to receive from the defaulting Party, subject to the limitation on damages set forth in Section 12.6, all of the damages incurred by the non-defaulting Party in connection with such termination, that shall be determined on a "cost-to-cover" basis. Such payment shall be the exclusive remedy of the non-defaulting Party in connection with the termination of this PPA, but shall not otherwise act to limit any of the non-defaulting Party's rights or remedies if the non-defaulting Party does not elect to terminate this PPA as its remedy for an Event of Default by the defaulting Party.

(C) In determining the losses that Seller will incur upon a termination of this Agreement by Seller under this Section 12.4, Buyers understand and agree that Seller may not be able to sell the Solar Energy Output on a commercially reasonable basis, and therefore Seller would not be able to mitigate its losses by selling the Solar Energy Output to a third-party, and therefore its losses would equal the net present value (determined using a discount rate of five percent (5%)) at the time of termination of all Solar Energy Output that would have been produced from the date of termination of the

PPA through the end of the Term (had the PPA not been terminated), minus avoided operating costs. If the PPA is terminated by Seller under this Section 12.4 during the first seven (7) years after the Commercial Operation Date, Seller's losses will include any anticipated recapture of Tax Credits and lost depreciation. After Buyers make a termination payment to Seller, if Seller is able to enter into new arrangements to sell the Solar Energy Output and Renewable Energy Benefits of the Facility, then Seller shall recalculate the termination payment based on such new arrangements and shall reimburse Buyers in the amount of the reduced termination payment.

(D) Subject to Section 12.4(E), in determining the losses that Buyer will incur upon a termination of this Agreement by Buyer under this Section 12.4, notwithstanding anything herein to the contrary (other than the provisions of Section 12.4(E)), Buyers' cost-to-cover losses shall be calculated using the projected Avoided Cost Rate as the replacement cost of electricity, and using the LD REC Input as the replacement cost of Renewable Energy Benefits. Such determination of Buyer's losses shall be based on the net present value (determined using a discount rate of five percent (5%)) of losses for the remainder of the Term at the time of termination.

(E) Seller's liability under Section 12.4(D) shall be limited to [redacted] (including amounts collected from the Seller Credit Support); provided, if Seller is able to enter into new arrangements to sell the Solar Energy and RECs attributable to Solar Energy within two (2) years of the date of termination and the pricing for such Solar Energy or RECs is greater than pricing under this PPA, then Buyers' cost-to-cover losses shall be recalculated to reflect the differences between the prices included in such new arrangements entered into by Seller and the lower prices under this PPA, and Seller shall pay Buyers the amount of the resulting increased termination payment without regard to the limitation of liability stated in this Section 12.4(E). The obligation to make such increased termination shall survive the termination of this PPA.

12.5 <u>Remedies Cumulative</u>. Subject to limitations on damages set forth in Section 12.6, each right or remedy of the Parties provided for in this PPA shall be cumulative of and shall be in addition to every other right or remedy provided for in this PPA, and the exercise, or the beginning of the exercise, by a Party of any one or more or the rights or remedies provided for herein shall not preclude the simultaneous or later exercise by such Party of any or all other rights or remedies provided for herein.

12.6 <u>Waiver and Exclusion of Other Damages</u>. The Parties confirm that the express remedies and measures of damages provided in this PPA satisfy the essential purposes hereof. If no remedy or measure of damages is expressly herein provided, the obligor's liability shall be limited to direct, actual damages only, which shall include cover damages and the related costs to procure alternative arrangements. Neither Party shall be liable to the other Party for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages by statute, in tort or contract (except to the extent expressly provided herein); provided, that if either Party is held liable to a third party for such damages, and the Party held liable for such damages is entitled under Article 17 to indemnification therefor from the other Party hereto, the indemnifying Party shall be liable for, and obligated to reimburse the indemnified Party for, such damages, all in accordance with the indemnification provisions of Article 17 hereof. To the extent any damages are required to be paid hereunder are described as or deemed liquidated, the Parties acknowledge that such damages do not constitute a penalty, that such damages are difficult or impossible to determine, that otherwise obtaining an adequate remedy is inconvenient, and that such damages constitute a reasonable approximation of the harm or loss.

12.7 Duty to Mitigate. Each Party agrees that it has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this PPA.

12.8 Non-Recourse. Each Buyer acknowledges and agrees that no owner, member, investor, lender, lessor, officer, director, employee, or agent of Seller shall have any obligation to Buyers arising under this PPA, and that Buyers shall seek recourse solely against Seller, its assets, and the Seller Credit Support in the event of any breach of this PPA by Seller. Seller acknowledges and agrees that no owner, member, investor, lender, lessor, officer, director, employee, or agent of a Buyer shall have any obligation to Seller arising under this PPA, and that Seller shall seek recourse solely against Buyers and their assets in the event of any breach of this PPA by a Buyer.

ARTICLE 13
Contract Administration and Notices

13.1 Notices in Writing. Notices required by this PPA shall be addressed to the other Party at the addresses noted in Exhibit A as either Party updates them from time to time by written notice to the other Party. Any notice, request, consent, or other communication required or authorized under this PPA to be given by one Party to the other Party shall be in writing. It shall be made by personal delivery, recognized express courier, or electronic mail (immediately followed by recognized express courier). Any such notice, request, consent, or other communication shall be deemed to have been received by the close of the Business Day on which it was hand delivered or transmitted electronically (unless hand delivered or transmitted after such close, in which case it shall be deemed received at the close of the next Business Day). Real-time or routine communications concerning Facility operations shall be exempt from this Section.

13.2 Records. Seller and Buyers shall each keep and maintain complete and accurate records and all other data required by each of them for the purposes of proper administration of this PPA, including such records as may be required by any Governmental Authority or pursuant to Applicable Law. All records of Seller and Buyers pertaining to the operation of the Facility and/or this PPA as specified herein or otherwise shall be maintained at the Facility or in an office of Seller or Buyers, as applicable, in such format as may be required by Applicable Law and/or any Governmental Approval. Each Party shall have the right, upon reasonable prior written notice to the other Party and at its own expense, during normal business hours, to examine and/or make copies of the records and data of such other Party relating to confirmation of such Party's performance of its obligations under this PPA (including all records and data relating to or substantiating any charges paid by or to such other Party under this PPA, MWh generated by the Facility, Seller's operating procedures, the Facility equipment manuals, and Facility O&M Records).

(A) Operating and Maintenance Records. Seller shall maintain an accurate and up-to-date operating log, in electronic format, with records of solar irradiation and energy production for each clock hour, changes in operating status, meteorological data, maintenance, any other operating or maintenance records as may be required by state or federal regulatory authorities and pursuant to any Non-Governmental Compliance Obligations, Forced Outages, agreements associated with the Facility, operating logs, blueprints for construction, operating manuals, all warranties on equipment, and all documents, including supply contracts, whether in printed or electronic format, that Seller uses or maintains for the operation of the Facility (collectively, the "O&M Records").

(B) Billing and Payment Records. To facilitate payment and verification, Seller and Buyers shall keep all books and records necessary for billing and payments in accordance with the provisions of Article 9 and grant the other Party reasonable access to those records. All records of Seller pertaining to the operation of the Facility shall be maintained at the Site or in an office of Seller.

13.3 Provision of Real Time Data. Upon request from Buyers, Seller shall provide real-time electronic access to Buyers of all solar irradiance and meteorological data collected at the Facility and corresponding unit availability data as well.

ARTICLE 14
Force Majeure and Seller Delivery Excuse

14.1 Definition of Force Majeure Event.

(A) "Force Majeure" shall mean a cause or event that actually and proximately prevents either Party, in whole or in part, from performing any of its obligations under this PPA including, acts of God; unusually severe actions of the elements such as floods, inundation, landslides, earthquake, lightning, hurricanes, or tornadoes; unusually severe weather; terrorism; war (whether or not declared); sabotage; acts or threats of terrorism; riots or public disorders; delays in obtaining necessary permits and regulatory approvals (except as provided below in this Section 14.1(A)); strikes or labor disputes not expressly excluded below; actions or failures to act of an unaffiliated third party supplier of goods or services (to the extent caused by an event which would meet the definition of Force Majeure); equipment failure; environmental issues not identified in reports and studies prepared by Seller and which delay construction of the Facility; actions or failures to act of any Governmental Authority (including, except as provided below in this Section 14.1(A), the failure to issue permits); blockade; embargo; military or governmentally usurped power, expropriation, or requisition to the extent preventing or delaying the performance of the Party claiming Force Majeure; or any other event beyond the reasonable control of the Party claiming Force Majeure, whether or not foreseeable, but only to the extent the Party claiming Force Majeure is unable to prevent, avoid or overcome any of the events described above in this Section 14.1 through the exercise of commercially reasonable efforts, and such event is not the result of the fault or negligence of the Party claiming Force Majeure. Notwithstanding the foregoing, failure of a Governmental Authority to issue any permit serving as the basis for a Buyers' CP or Seller's CP shall not constitute Force Majeure.

(B) "Force Majeure" shall not include: (i) any failure of, or delay in performance, or any full or partial curtailment in the electric output of the Facility that is caused by a labor dispute or strike by Seller's employees or any employees of Seller's contractors employed at the Facility (except to the extent arising out of a strike or labor action not directed specifically at the Seller or the Facility, including without limitation, a national or regional strike), (ii) market changes in, or that otherwise effect, the price of energy, capacity or Renewable Energy Benefits, or (iii) any Change in Applicable Law that effects the value or existence of Renewable Energy Benefits.

14.2 Effect of Force Majeure.

(A) In no event will any delay or failure of performance caused by Force Majeure extend this PPA beyond its stated Term. Notwithstanding any other provision in this PPA to the contrary, in the event that any delay or failure of performance caused by Force Majeure affecting Seller continues for an uninterrupted period of twelve (12) months from its inception, either Seller or Buyers may, at any time following the end of such period if the Force Majeure event is still in effect, terminate this PPA upon written notice to the other Parties, without further obligation by either Party except as to costs and balances incurred prior to the effective date of such termination.

(B) Except as otherwise provided in this PPA, each Party shall be excused from performance when non-performance was caused, directly or indirectly, by a Force Majeure event but only and to the extent thereof, and only if: (i) the non-performing Party gives the other Party notice describing the occurrence of the Force Majeure event as described in Section 14.3; (ii) the non-performance is of no greater scope and of no longer term than is required by the Force Majeure event; and (iii) the non-performing Party uses commercially reasonable efforts to remedy its inability to perform.

(C) The existence of a condition of Force Majeure event shall not relieve the Parties of obligations under this PPA (including payment obligations) to the extent that such performance of such obligations is not precluded by the condition or Force Majeure event.

14.3 Notification Obligations. In the event of any delay or nonperformance resulting from a Force Majeure event, the Party claiming that a Force Majeure event has occurred shall notify the other Party immediately by telephone and/or email, and in writing, within five (5) Days of such occurrence, of the nature, cause, date of commencement thereof, and the anticipated duration, and shall indicate whether any deadlines or date(s) imposed hereunder may be affected thereby. The suspension of performance shall be of no greater scope and of no greater duration than the cure for the Force Majeure event requires. A Party claiming that a Force Majeure event has occurred shall not be entitled to any relief therefor unless and until conforming notice is provided. The Party claiming that a Force Majeure event has occurred shall notify the other Party of the cessation of the Force Majeure event or of the conclusion of the affected Party's cure for the Force Majeure event, in either case within two (2) Business Days thereof.

14.4 Duty to Mitigate. The Party claiming that a Force Majeure event has occurred shall use its best efforts to cure the cause(s) preventing its performance of this PPA and shall provide to the other Party weekly progress reports describing actions taken to end the Force Majeure event and perform its obligations pursuant to Section 14.5 below; provided, however, that the settlement of strikes, lockouts and other labor disputes shall be entirely within the discretion of the affected Party, and such Party shall not be required to settle such strikes, lockouts or other labor disputes by acceding to demands which such Party deems to be unreasonable.

14.5 Force Majeure Restoration.

(A) In the event that, as a result of one or more Force Majeure event(s) or its or their effects or by any combination thereof, the construction or operation of the Facility or any part thereof is affected and is not restored or remedied within thirty (30) Days following the date the Force Majeure event(s) began, then Seller shall prepare and deliver to Buyers a Restoration Report pursuant to Section 14.7.

(B) Subject to clause (C) below, Seller shall proceed with the remedying of the construction or operation of the Facility ("Restoration") in accordance with a schedule contained in the relevant Restoration Report, as defined in Section 14.7 hereof (the "Restoration Schedule"). The cost of such Restoration shall be the sole responsibility of Seller and no compensation shall be payable by Buyers to Seller with respect to any damage to the Facility as a result of the Force Majeure event.

(C) If Seller's Financing Documents do not require the use of insurance proceeds for the prepayment of Seller's obligations thereunder, then Seller shall be obligated to use all insurance proceeds to restore the Facility, and the Demonstrated Capacity of the Facility after such restoration shall be adjusted to the actual installed capacity of the Facility, notwithstanding that such capacity is lower than the Minimum Demonstrated Capacity. If Seller's Financing Documents require the use of insurance proceeds for the prepayment of Seller's obligations thereunder then Seller shall have the right to terminate this PPA without further liability to Buyers.

14.6 Restoration Consents. Notwithstanding anything herein to the contrary, Seller shall not be required to proceed with any Restoration unless and until it shall have received all necessary third-party consents and any Governmental Approvals required therewith. If Seller does not receive any such third-party consents or any Governmental Approvals required therewith for any reason (other than an act, omission or default of Seller) within six (6) Months after the date that it becomes obligated to proceed with such Restoration, then either Seller or Buyers shall have the right to terminate this PPA.

14.7 Preparation of Restoration Report. When required by Section 14.5, Seller shall commence the preparation of an appraisal report (the "Restoration Report") within thirty (30) Days after the date it was required to provide a notice under Section 14.3 and shall deliver a copy of such Restoration Report to Buyers within sixty (60) Days after provision of such notice was required. Buyers shall provide Seller such information as it reasonably requires to prepare such Restoration Report. The Restoration Report shall be accompanied by reasonable supporting data and certificates and reports of financial and technical advisers of Seller, as appropriate or as reasonably requested by Buyers, in support of the Force Majeure event in question, and shall include (A) a description of such Force Majeure event and its impact on the Facility, (B) an estimate in good faith of the time required to restore the Facility (insofar as practicable) to its condition immediately prior to the occurrence of the Force Majeure event, and (C) a proposed Restoration Schedule.

14.8 Discussion of Restoration Report. Within fifteen (15) Days of the delivery of a Restoration Report to Buyers or such further time as the Parties may agree, the Parties shall meet to discuss the Restoration Report and any action to be taken.

ARTICLE 15
Representations, Warranties and Covenants

15.1 Seller's Representations, Warranties, and Covenants. Seller hereby represents and warrants to Buyers as follows as of the Effective Date and as of the Commercial Operation Date:

(A) Seller is a limited liability company duly organized, validly existing and in good standing under the laws of the state of Delaware. Seller is qualified to do business in the Commonwealth of Kentucky and each other jurisdiction where the failure to so qualify would have a material adverse effect on the business or financial condition of Seller; and Seller has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by Seller have been duly authorized by all necessary corporate action, and do not and will not:

(i) require any consent or approval by any governing body of Seller, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to Buyers upon execution of this PPA);

(ii) violate any Applicable Law, or violate any provision in any formation documents of Seller, the violation of which could have a material adverse effect on the ability of Seller to perform its obligations under this PPA;

(iii) result in a breach or constitute a default under Seller's formation documents or bylaws, or under any agreement relating to the management or affairs of Seller or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which Seller is a party or by which Seller or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of Seller to perform its obligations under this PPA; or

(iv) result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of Seller now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of Seller to perform its obligations under this PPA.

(C) The obligations of Seller under this PPA are valid and binding obligations of Seller, enforceable against the Seller by Buyers, subject to customary exceptions for public policy and bankruptcy.

(D) The execution and performance of this PPA will not conflict with or constitute a breach or default under any contract or agreement of any kind to which Seller is a party or any judgment, order, statute, or regulation that is applicable to Seller or the Facility.

(E) To the best knowledge of Seller, and except for those permits, consents, approvals, licenses and authorizations identified in writing by Seller to Buyers, all Governmental Approvals necessary for Seller's execution, delivery and performance of this PPA have been duly obtained and are in full force and effect.

(F) Seller shall comply with all Applicable Laws in effect or that may be enacted during the Term.

(G) As of the Commercial Operation Date, Seller shall have been certified as an "exempt wholesale generator" as such term is defined in the regulations of the Federal Energy Regulatory Commission.

(H) Seller has not taken action causing either Buyer to be deemed to be the registered "Generator Owner" or "Generator Operator" with respect to the Facility as such terms are used in the NERC Reliability Standards.

(I) Seller has not sold or committed to sell to any Person any Solar Energy Output, Renewable Energy Benefits or Capacity Rights to any Person.

(J) Seller either (i) owns the real property comprising the Site or (ii) has obtained the necessary real property rights to construct and operate the Facility on the Site throughout the Term.

(K) Seller will have as of the Commercial Operation Date, and shall thereafter maintain sufficient funds available to it to perform all obligations under this Agreement and to consummate the obligations contemplated pursuant hereto.

15.2 <u>Buyers' Representations, Warranties, and Covenants</u>. Each Buyer hereby represents and warrants to Seller as follows as of the Effective Date and as of the Commercial Operation Date:

(A) Such Buyer is a corporation, duly organized, validly existing and in good standing under the laws of the Commonwealth of Kentucky and is qualified in each other jurisdiction where the failure to so qualify would have a material adverse effect upon the business or financial condition of such Buyer. (KU is also incorporated in Virginia.) Such Buyer has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this PPA.

(B) The execution, delivery, and performance of its obligations under this PPA by such Buyer have been duly authorized by all necessary corporate action, and do not and will not:

(i) require any further consent or approval, including from such Buyer's Board of Directors;

(ii) violate any Applicable Law, or violate any provision in any corporate documents of such Buyer, the violation of which could have a material adverse effect on the ability of such Buyer to perform its obligations under this PPA;

(iii) result in a breach or constitute a default under such Buyer's corporate charter or bylaws, or under any agreement relating to the management or affairs of such Buyer, or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which such Buyer is a party or by which such Buyer or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a material adverse effect on the ability of such Buyer to perform its obligations under this PPA; or

(iv) result in, or require the creation or imposition of, any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature (other than as may be contemplated by this PPA) upon or with respect to any of the assets or properties of such Buyer now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a material adverse effect on the ability of such Buyer to perform its obligations under this PPA.

(C) The obligations of such Buyer under this PPA are valid and binding obligations of such Buyer, enforceable against it by the Seller, subject to customary exceptions for public policy and bankruptcy.

(D) The execution and performance of this PPA will not conflict with or constitute a breach or default under any contract or agreement of any kind to which such Buyer is a party or any judgment, order, statute, or regulation that is applicable to such Buyer.

(E) To the best knowledge of such Buyer, all required Governmental Approvals necessary for such Buyer's execution, delivery and performance of this PPA, other than Governmental Approvals identified as Buyer Conditions Precedent, have been duly obtained and are in full force and effect.

ARTICLE 16
Insurance

16.1 Evidence of Insurance.

(A) Seller shall, at least thirty (30) Days prior to the commencement of any work on the Facility, and thereafter, on or before June 1 of each year of the Term, provide Buyers with one (1) copy of insurance certificates reasonably acceptable to Buyers evidencing the insurance coverages required to be maintained by Seller in accordance with Exhibit B and this Article 16. Such certificates shall provide a waiver of any rights of subrogation against Buyers and their Affiliates and their respective officers, directors, agents, subcontractors, and employees; and shall contain such other endorsements and terms as required hereunder. All policies shall be written with insurers that Buyers, in their reasonable discretion, deem acceptable (such acceptance shall not be unreasonably withheld or delayed by Buyers). Seller's liability under this PPA shall not be limited to the amount of insurance coverage required herein.

16.2 Term and Modification of Insurance.

(A) All liability insurance required under this PPA shall cover occurrences during the term of this PPA. In the event that any insurance as required herein is commercially available only on a "claims-made" basis, such insurance shall provide for a retroactive date not later than the Effective Date.

16.3 Endorsements and Other Requirements.

(A) Insurers shall waive all rights of subrogation against Buyers and their Affiliates and their respective officers, directors, agents, subcontractors, and employees.

(B) The insurance required under this PPA shall be primary insurance. Any other insurance carried by Buyers shall be excess and not contributory with respect to the insurance required hereunder.

(C) The liability insurance required pursuant to Exhibit B shall be endorsed to include Buyers, their Affiliates, and their respective officers, directors, and employees as additional insureds only to the extent Buyers (or other additional insured) are vicariously liable for the negligence, acts or omissions of Seller. The liability insurance required pursuant to paragraphs (B) and (D) of Exhibit B shall state, that with respect to coverage of more than one insured, all terms, conditions, insuring agreements, and endorsements, with the exception of limits of liability, shall operate in the same manner as if there were a separate policy covering each insured.

ARTICLE 17
Indemnity

17.1 Indemnification.

(A) Each Buyer and Seller shall each be responsible for its own facilities. Buyers and Seller shall each be responsible for ensuring adequate safeguards for Buyers, Buyers' customers, and personnel and equipment belonging to Buyers, and for the protection of their own generating systems.

(B) Seller agrees, to the extent permitted by Applicable Law, to indemnify, pay, defend, and hold harmless the Buyers, their Affiliates, their respective officers, directors, employees, agents, and contractors (hereinafter called respectively, "Buyer Entities") from and against any and all claims, demands, costs, or expenses for loss, damages, or injury to persons or property of the Buyer Entities (or to third parties) directly caused by, arising out of, or resulting from:

(i) a breach by Seller of its covenants, representations, and warranties or obligations hereunder;

(ii) any act or omission by Seller or its contractors, agents, servants or employees in connection with the installation or operation of its generation system or the operation thereof in connection with the other Party's system;

(iii) any defect in, failure of, or fault related to, the Seller's generation system; or

(iv) the negligence or willful misconduct of the Seller or its contractors, agents, servants or employees.

(C) Each Buyer, on a several but not joint basis, agrees, to the extent permitted by Applicable Law, to indemnify, pay, defend, and hold harmless Seller, its Affiliates, their respective officers, directors, employees, agents, and contractors (hereinafter called respectively, "Seller Entities") from and against any and all claims, demands, costs, or expenses for loss, damages, or injury to persons or property of a Seller Entity (or to third parties) directly caused by, arising out of, or resulting from:

(i) a breach by such Buyer of its covenants, representations, and warranties or obligations hereunder; or

(ii) the negligence or willful misconduct of such Buyer or its contractors, agents, servants or employees.

17.2 Indemnification for Fines and Penalties. Any fines or other penalties incurred by a Party (other than fines or penalties due to the negligence or intentional acts or omissions of the other Party) for non-compliance with any municipal, state or federal laws shall be the sole responsibility of the non-complying Party.

17.3 Notice of Proceedings. Each Party shall promptly notify the other Party of any loss or proceeding in respect of which such notifying Party is or may be entitled to indemnification pursuant to Section 17.1. Such notice shall be given as soon as reasonably practicable after the relevant Party becomes aware of the loss or proceeding and that such loss or proceeding may give rise to an indemnification. The delay or failure of such Indemnified Party to provide the notice required pursuant to this Section 17.3 to the other Party shall not release the other Party from any indemnification obligation it may have to such Indemnified Party except (i) to the extent that such failure or delay materially and adversely affected the Indemnifying Party's ability to defend such action or increased the amount of the loss, and (ii) that the Indemnifying Party shall not be liable for any costs or expenses of the Indemnified Party in the defense of the claim, suit, action or proceeding during such period of failure or delay.

17.4 Defense of Claims.

(A) The Indemnifying Party shall be entitled, at its option, to assume and control the defense of such claim, action, suit or proceeding at its expense with counsel of its selection, subject to the prior approval of the Indemnified Party, which shall not be unreasonably withheld.

(B) Unless and until the Indemnifying Party assumes control of the defense of a claim, suit, action or proceeding in accordance with clause (A) above, the Indemnified Party shall have the right, but not the obligation, to contest, defend and litigate, with counsel of its own selection, any claim, action, suit or proceeding by any third party alleged or asserted against such Party in respect of, resulting from, related to or arising out of any matter for which it is entitled to be indemnified hereunder, and the reasonable costs and expenses thereof shall be subject to the indemnification obligations of the Indemnifying Party hereunder.

(C) Neither the Indemnifying Party nor the Indemnified Party shall be entitled to settle or compromise any such claim, action, suit or proceeding without the prior consent of the other; provided, however, that after agreeing in writing to indemnify the Indemnified Party, the Indemnifying Party may, subject to clause (D) below, settle or compromise any claim without the approval of such Indemnified Party. If a Party settles or compromises any claim, action, suit or proceeding in respect of which it would otherwise be entitled to be indemnified without the prior consent of the Indemnifying Party, the Indemnifying Party shall be excused from any indemnification obligation in respect of such settlement or compromise.

(D) Following the acknowledgement of the indemnification and the assumption of the defense by the Indemnifying Party pursuant to clause (A) above, the Indemnified Party shall have the right to employ its own counsel, and such counsel may participate in such action, but the fees and expenses of such counsel shall be at the expense of the Indemnified Party, when and as incurred, unless: (i) the Indemnified Party shall have reasonably concluded and specifically notified the Indemnifying Party that there may be a conflict of interest between the Indemnifying Party and the Indemnified Party in the conduct of the defense of such action; or (ii) the Indemnifying Party shall not in fact have employed independent counsel reasonably satisfactory to the Indemnified Party to assume the defense of such action and shall have been so notified by the Indemnified Party.

17.5 Subrogation.

Upon payment of any indemnification pursuant to Section 17.1 above, the Indemnifying Party, without any further action, but subject to such limits as may be imposed below, shall be subrogated to any and all Claims that the Indemnified Party may have relating thereto, and the Indemnified Party shall, at the request and expense of the Indemnifying Party, cooperate with the Indemnifying Party and give at the request and expense of the Indemnifying Party such further assurances as are necessary or advisable to enable the Indemnifying Party vigorously to pursue such Claims.

ARTICLE 18
Legal and Regulatory Compliance

18.1 Applicable Laws. Seller shall promptly notify Buyer of any investigations, notices, or findings of violation of Applicable Law from any Governmental Authority, including any audit, notification, inspection, or inquiry that has been commenced by any Governmental Authority in respect of a potential or possible violation of Applicable Law.

18.2 Governmental Approvals. Each Party shall timely and lawfully procure and maintain in good standing, at its own cost and expense, all Governmental Approvals and shall timely and properly pay its respective charges and fees in connection therewith.

18.3 Compliance with Reliability Standards. To the extent that Seller contributes in whole or in part to actions that result in monetary penalties being assessed to Buyer by NERC, FERC, the RE or any successor agency, for lack of compliance with reliability standards, Seller shall reimburse Buyer for its share of monetary penalties.

18.4 Change in Applicable Law. No Change in Applicable Law that eliminates, reduces or otherwise modifies any obligations of a Buyer to obtain Renewable Energy Benefits to comply with Applicable Law shall, in any such case, modify the obligations of the Parties hereunder.

ARTICLE 19
Assignment and Other Transfer Restrictions

19.1 No Assignment Without Consent. Except as permitted in this Article 19, neither Party shall assign this PPA or any portion thereof, without the prior written consent of the other Party; provided, (i) at least thirty (30) Days prior notice of any such assignment shall be given to the other Party; (ii) any assignee shall expressly assume the assignor's obligations hereunder; (iii) no assignment shall relieve the assignor of its obligations hereunder in the event the assignee fails to perform; (iv) no assignment shall impair any security given by Buyer hereunder; and (v) before this PPA is assigned, the assignee must first obtain such approvals as may be required by all applicable regulatory bodies.

19.2 Transfers. Notwithstanding Section 19.1 and Article 7.1(C), but subject to the limitations in Section 19.3, Seller may: assign, pledge, hypothecate, or otherwise transfer, as and for, among other purposes, collateral security, in connection with any financing or the refinancing of the Facility, including a sale of this PPA, together with a sale of the Facility, combined with the lease back to Seller of the PPA and Facility, as part of a sale-leaseback financing transaction. In connection with any such permitted transfer by Seller, Buyer agrees to execute a written consent to such collateral assignment as may be reasonably requested, which collateral assignment may include, among other terms, Buyer's agreement not to terminate this PPA on account of any Event of Default without written notice to the Financing Parties and first providing the Financing Parties with such opportunity to cure such Event of Default. If such written consent is not requested, Seller shall notify Buyer of any such assignment to the Financing Parties no later than thirty (30) Days after the assignment. Seller may subcontract its duties or obligations under this PPA without the prior written consent of Buyer, provided, that no such subcontract shall relieve Seller of any of its duties or obligations hereunder.

19.3 Buyers' Consent. A Buyer may withhold its consent to a proposed assignment by Seller pursuant to Section 19.1 if the proposed transferee is: (A) an entity that at the time of such proposed transfer is, or within the five years prior to the Commercial Operation Date has been, adverse to a Buyer in a litigation or administrative proceeding; or (B) not experienced (and has not contracted for the operation of the Facility with a third-party that is experienced) in operating and maintaining a solar power generation facility of at least 10 MWac.

ARTICLE 20
Miscellaneous

20.1 Waiver. The failure of either Party to enforce or insist upon compliance with or strict performance of any of the terms or conditions of this PPA, or to take advantage of any of its rights thereunder, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect.

20.2 Rate Changes.

(A) The terms and conditions and the rates for service specified in this PPA shall remain in effect for the term of the transaction described herein. Absent the Parties' written agreement, this PPA shall not be subject to change by application of either Party pursuant to Section 205 or 206 of the Federal Power Act.

(B) Absent the agreement of all Parties to the proposed change, the standard of review for changes to this PPA whether proposed by a Party (acting unilaterally in violation of this Section 20.2), a non-party, or the FERC acting *sua sponte* shall be the "public interest" standard of review set forth in United Gas Pipe Line v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) (the "Mobile-Sierra doctrine").

20.3 Disclaimer of Third Party Beneficiary Rights. In executing this PPA, Buyer does not, nor should it be construed to, extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with Seller. Nothing in this PPA shall be construed to create any duty to, or standard of care with reference to, or any liability to, any Person not a party to this PPA.

20.4 Relationship of the Parties.

(A) This PPA shall not be interpreted to create an association, joint venture, or partnership between the Parties nor to impose any partnership obligation or liability upon either Party. Neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as an agent or representative of, the other Party.

(B) Each Party shall be solely liable for the payment of all wages, taxes, and other costs related to the employment of persons to perform services for such Party, including all federal, state, and local income, social security, payroll, and employment taxes and statutorily mandated workers' compensation coverage. None of the persons employed by a Party shall be considered employees of the other Party for any purpose; nor shall a Party represent to any person that he or she is or shall become an employee of the other Party.

20.5 Survival of Obligations. Cancellation, expiration, or earlier termination of this PPA shall not relieve the Parties of obligations that by their nature should survive such cancellation, expiration, or termination, prior to the term of the applicable statute of limitations, including warranties, remedies, or indemnities which obligation shall survive for the period of the applicable statute(s) of limitation.

20.6 Severability. In the event any of the terms, covenants, or conditions of this PPA, its Exhibits or Schedules, or the application of any such terms, covenants, or conditions, shall be held invalid, illegal, or unenforceable by any court or administrative body having jurisdiction, all other terms, covenants, and conditions of the PPA and their application not adversely affected thereby shall remain in force and effect; provided, however, that Buyer and Seller shall negotiate in good faith to attempt to implement an equitable adjustment in the provisions of this PPA with a view toward effecting the purposes of this PPA by replacing the provision that is held invalid, illegal, or unenforceable with a valid provision the economic effect of which comes as close as possible to that of the provision that has been found to be invalid, illegal or unenforceable.

20.7 Complete Agreement; Amendments. The terms and provisions contained in this PPA constitute the entire agreement between Buyers and Seller with respect to the subject matter hereof, and shall supersede all previous communications, representations, or agreements, either oral or written, between Buyer and Seller with respect to the sale of Solar Energy Output and Renewable Energy Benefits from the Facility. This PPA and the Exhibits and Schedules attached hereto may be amended, changed, modified, or altered, provided that such amendment, change, modification, or alteration shall be in writing and signed by both Parties hereto

20.8 Binding Effect. This PPA, as it may be amended from time to time pursuant to this Article, shall be binding upon and inure to the benefit of the Parties hereto and their respective successors-in-interest, legal representatives, and assigns permitted hereunder.

20.9 Headings. Captions and headings used in this PPA are for ease of reference only and do not constitute a part of this PPA.

20.10 Counterparts. This PPA or any supplement, modification, amendment, or restatement hereof may be executed in two or more counterpart copies of the entire document or of signature pages to the document, each of which may have been executed by one or more of the signatories hereto and thereto and deliveries by mail, courier, telecopy or other electronic means, but all of which taken together shall constitute a single agreement, and each executed counterpart shall have the same force and effect as an original instrument.

20.11 Governing Law. The interpretation and performance of this PPA and each of its provisions shall be governed and construed in accordance with the laws of the Commonwealth of Kentucky notwithstanding its conflict of laws rules or any principles that would trigger the application of any other law.

20.12 Confidentiality.

(A) For purposes of this Section 20.12, “Disclosing Party” refers to the Party disclosing information to the other Party, and the term “Receiving Party” refers to the Party receiving information from the other Party.

(B) The Parties agree to and acknowledge that certain terms, conditions and provisions of this PPA will need to be disclosed in connection with Buyers’ satisfaction of the conditions set forth in Section 6.2, including seeking PSC approvals and with respect to seeking transmission service from the Interconnection Provider, and Buyers shall be permitted to make any necessary disclosures of Confidential Information in connection therewith (including any ongoing requirements), provided that Buyers shall use reasonable efforts to keep such disclosures confidential to the extent permitted. The Parties agree to and acknowledge that certain terms, conditions and provisions of this PPA will need to be disclosed in connection with Seller's satisfaction of the conditions set forth in Section 6.1, including seeking approval from the Kentucky Public Service Commission Electric Generation and Transmission Siting Board and with respect to seeking transmission service, and Seller shall be permitted to make any necessary disclosures of Confidential Information in connection therewith (including any ongoing requirements), provided that Seller shall use reasonable efforts to keep such disclosures confidential to the extent permitted.

(C) In any proceeding before any applicable Governmental Authority relating to this PPA, Seller and Buyers shall each be entitled to disclose Confidential Information as permitted under Applicable Law. In such event, Seller and/or Buyers shall take all reasonable steps to limit the scope of any disclosure of Confidential Information and shall use its best efforts to make such disclosure of Confidential Information in an executive session or any protective order or other similar procedure.

(D) Other than in connection with this PPA, the Receiving Party will not use the Confidential Information (as defined in clause (F) below) and will keep the Confidential Information confidential. The Confidential Information may be disclosed to the Receiving Party or its affiliates and any of their directors, officers, employees, financial advisors, legal counsel, accountants, authorized agents of the Receiving Party identified in writing to the Disclosing Party, and current and potential investors (collectively, 'Receiving Party's Representatives"), but only if such Receiving Party's Representatives need to know the Confidential Information in connection with this PPA. The Parties agree that (i) such Receiving Party's Representatives will be informed by the Receiving Party of the confidential nature of the Confidential Information and the requirement and the limitations of its use, (ii) such Receiving Party's Representatives will be required to agree to and be bound by the terms of this Section 20.12 as a condition of receiving the Confidential Information, and (iii) in any event, the Receiving Party will be responsible for any disclosure of Confidential Information, or any other breach of confidentiality provisions of this PPA, by any of its Receiving Party's Representatives. The Receiving Party shall not disclose the Confidential Information to any person other than as permitted hereby, and shall safeguard the Confidential Information from unauthorized disclosure using the same degree of care as it takes to preserve its own confidential information (but in any event no less than a reasonable degree of care). To the extent the Disclosing Party is required to submit Confidential Information to a Governmental Authority, the Disclosing Party shall use all available means to ensure that such Confidential Information is not made public.

(E) If the Receiving Party or its Receiving Party's Representatives are requested or required (by a FOIA request, oral question, interrogatories, requests for information or documents, subpoena, civil investigative demand or similar process, or by applicable law) to disclose any Confidential Information, the Receiving Party shall promptly notify the Disclosing Party of such request or requirement, if that notification can be made without violating the terms of such compelled disclosure, so that the Disclosing Party may seek an appropriate protective order or waive compliance with this Section 20.12 with respect to such disclosure. If, in the absence of a protective order or the receipt of a waiver hereunder, the Receiving Party or its Receiving Party's Representatives are, in the opinion of their legal counsel, compelled to disclose the Confidential Information, the Receiving Party and its Receiving Party's Representatives may disclose only such of the Confidential Information to the party compelling disclosure as is required by law and, in connection with such compelled disclosure, the Receiving Party and its Receiving Party's Representatives shall use their reasonable efforts to obtain from the party to whom disclosure is made written assurance that confidential treatment will be accorded to such portion of the Confidential Information as is disclosed.

(F) As used in this Section 20.12, "Confidential Information" means all information that is furnished in connection with this PPA to the Receiving Party or its Receiving Party's Representatives by the Disclosing Party, or to which the Receiving Party or its Receiving Party's Representatives have access by virtue of this PPA (in each case, whether such information is furnished or made accessible in writing, orally, visually or by any other (including electronic) means), or which concerns this PPA, the Disclosing Party or the Disclosing Party's stockholders, members, affiliates or subsidiaries, and which is designated by the Disclosing Party at the time of its disclosure, or promptly thereafter, as "confidential" (whether by stamping any such written material or by memorializing in writing the confidential nature of any such oral or visual information). Any such information furnished to the Receiving Party or its Receiving Party's Representatives by a director, officer, employee, affiliate, stockholder, consultant, agent, or representative of the Disclosing Party will be deemed furnished by the Disclosing Party for the purpose of this PPA. Notwithstanding the foregoing, the following will not constitute Confidential Information for purposes of this PPA:

(i) information which is or becomes generally available to the public other than as a result of a disclosure or other act by the Receiving Party or its Receiving Party's Representatives;

(ii) information which can be shown by the Receiving Party to have been already known to the Receiving Party on a non-confidential basis prior to being furnished to the Receiving Party by the Disclosing Party;

(iii) information that becomes available to the Receiving Party on a non-confidential basis from a source other than the Disclosing Party or a representative of the Disclosing Party if to the knowledge of the Receiving Party such source was not subject to any prohibition against transmitting the information to the Receiving Party; and

(iv) information developed by the Parties during the negotiation of this PPA that relates solely to this PPA (as opposed to confidential business or operating information of either Party), which information shall be deemed proprietary to both Parties, each of whom shall be free to use such information, as they would any information already known to the Parties prior to the negotiation of this PPA.

(G) The Confidential Information will remain the property of the Disclosing Party. Any Confidential Information that is reduced to writing, except for that portion of the Confidential Information that may be found in analyses, compilations, studies or other documents prepared by or for the Receiving Party in connection with this PPA, will be returned to the Disclosing Party immediately upon its request after expiration or termination of this PPA, unless such Confidential Information has been destroyed by the Receiving Party, and no copies will be retained by the Receiving Party or its Receiving Party's Representatives, unless the Parties agree otherwise. That portion of the Confidential Information that may be found in analyses, compilations, studies or other documents prepared by or for the Receiving Party, oral or visual Confidential Information, and written Confidential Information not so required to be returned will be held by the Receiving Party and kept subject to the terms of this PPA, or destroyed.

(H) It is understood and agreed that neither this PPA nor disclosure of any Confidential Information by the Disclosing Party to the Receiving Party shall be construed as granting to the Receiving Party or any of its Receiving Party's Representatives any license or rights in respect of any part of the Confidential Information disclosed to it, including any trade secrets included in any such Confidential Information.

20.13 <u>Press Releases and Media Contact</u>. Upon the request of either Party, the Parties shall develop a mutually agreed joint press release to be issued describing the location, size, type and timing of the Facility, the long-term nature of this PPA, and other relevant factual information about the relationship. In the event during the Term, either Party is contacted by the media concerning this PPA or the Facility, the contacted Party shall inform the other Party of the existence of the inquiry, and shall jointly agree upon the substance of any information to be provided to the media.

20.14 <u>Jurisdiction; Venue; Waiver of Jury Trial</u> With respect to any disputes arising out of or related to this PPA and not resolved through regular discussion, the Parties will use all reasonable efforts to reach a satisfactory solution by referring the dispute to senior management (officer of a corporation or manager or managing member of a limited liability company) of each of the Parties. Senior management of the Parties will meet (in person or telephonically) as soon as possible, on no less than seven (7) days' written notice, unless specifically agreed otherwise and shall negotiate in good faith. Senior management of the Parties shall examine any submissions by the Parties, and shall, if the dispute cannot be resolved within two (2) days (or longer as agreed to by the Parties), agree to convene for further negotiations aimed at resolving the dispute. Should senior management of the Parties be unable to resolve the dispute within thirty (30) days after commencement of negotiation by such senior management, if any of the Parties fails to comply with the time periods set forth above, or commencement of litigation is necessary to comply with a statute of limitations or contractual obligation, then the Parties agree that upon prior written notice to the other Parties, the Parties consent to the exclusive jurisdiction of, and venue in, the state or federal courts located in Louisville, Kentucky to resolve such dispute. EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO TRIAL BY JURY IN RESPECT OF ANY CLAIM BASED ON, ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY.

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IN WITNESS WHEREOF, the Parties have executed this PPA.

Seller:

Rhudes Creek Solar, LLC

By: ____________________

Name: TIMOTHY C. KIM

Title: PRESIDENT

Date: 11/21/2019

Buyer:

Louisville Gas and Electric Company

By: ____________________

Name: David S. Sinclair

Title: VP Energy Supply + Analysis

Date: 11-22-19

JD

Kentucky Utilities Company

By: ____________________

Name: David S Sinclair

Title: VP Energy Supply + Analysis

Date: 11-22-19

JD

EXHIBIT A

NOTICE ADDRESSES

To Seller:

ibV Energy Partners LLC
777 Brickell Ave. Suite 500
Miami, FL 33131
Attention: Timothy C. Kim

With a copy to:

Henry R. King
Reed Smith LLP
506 Carnegie Center
Suite 300
Princeton, NJ 08540

To Buyers:

Director – Power Supply
Charles R. Schram
LG&E and KU Energy LLC
220 W. Main St.
Louisville, KY 40202
Telephone: [redacted]
email: [redacted]

With a copy to:

Senior Corporate Attorney
James J. Dimas
LG&E and KU Services Company
220 W. Main St.
Louisville, KY 40202
Telephone: [redacted]
email: [redacted]

EXHIBIT B

INSURANCE COVERAGES

A. Worker's Compensation Insurance. To cover obligations imposed by federal and state statutes pertaining to Seller's employees, and Employer's Liability Insurance with a limit of one million Dollars ($1,000,000).

B. Commercial General Liability Insurance, or the equivalent, with a limit of one million Dollars ($1,000,000) per occurrence. This policy shall include coverage for bodily injury liability, broad form property damage liability, blanket contractual, owner's protective, products liability and completed operations. Each Buyer shall be named as an additional insured with regard to this coverage.

C. Business Automobile Liability Insurance, or the equivalent, with limit of one million Dollars ($1,000,000) per accident with respect to Seller's vehicles whether owned, hired, or non-owned.

D. Excess Liability. Excess Liability Insurance covering claims in excess of the underlying insurance described in paragraphs (A) (with respect to only Employer's Liability Insurance), (B) and (C) with a limit per occurrence of twenty-five million Dollars ($25,000,000).

The amounts of insurance required in the foregoing paragraphs (A), (B), (C) and (D) may be satisfied by purchasing coverage in the amounts specified or by any combination of primary and excess insurance, so long as the total amount of insurance meets the requirements specified above,

E. Property Insurance. During construction and operation, Seller shall provide standard form "All Risk" insurance covering 100% of the project cost. The All-Risk property insurance shall cover physical loss or damage to the Facility including the period during testing and startup. A deductible may be carried, which deductible shall be the absolute responsibility of Seller. All-Risk property insurance shall include coverage for fire, flood, wind and storm, tornado and earthquake with respect to facilities similar in construction, location and occupancy to the Facility.

EXHIBIT C
"FORM OF SURETY BOND" – TEMPLATE 1

BOND NUMBER __XXXXXXXX

[SURETY COMPANY]
POWER PURCHASE AGREEMENT BOND

KNOW ALL MEN BY THESE PRESENTS, That we ___DEV/PROJECT CO LLC_____ (hereinafter called "Principal"), and [SURETY] authorized to do business in the State of ______[STATE]_________ (hereinafter called "Surety") are held and firmly bound unto _____[PPA COUNTERPARTY]_________ (hereinafter called "Obligee") as Obligee, for such monetary amount as incurred by the Obligee, not to exceed the penal sum of ___XX Million XX Hundred Thousand and 00/100______($_XX,XXX,XX.00__) DOLLARS, good and lawful money of the United States of America, the payment of which, well and truly to be made, we do bind ourselves, our heirs, administrators, executors, successors, and assigns, jointly and severally, firmly by these presents.

WHEREAS the above bounded Principal has entered into a certain written Contract with the above named Obligee, effective the _________ day of ___________________,20____, for the __Power Purchase Agreement______ which Contract is hereby referred to and made a part hereof as fully and to the same extent as if copies at length were attached herein.

The obligation of this Performance Bond shall be null and void unless: (1) the above Contract is in writing, and has been fully executed by both the Principal and the Obligee; (2) the Principal is in default under the above Contract, and is declared by the Obligee thereafter to be in default; and (3) the Obligee has provided written notice of the default to the Surety as promptly as possible, and in any event, **within ten (10) days after notice of such default is sent to Principal.**

The Surety, at the sole election and discretion of the Surety, may take any of the following actions:

1. With notice to the Obligee, provide financial assistance to the Principal to effect a remedy any contractual default by the Principal; or

2. Determine the amount for which the Surety may be liable to the Obligee, and as soon as practicable thereafter, tender payment thereof to the Obligee; or

3. Pay the full amount of the above penal sum in complete discharge and exoneration of this Performance Bond, and of all liabilities of the Surety relating hereto.

If the Surety so elects to act, all payments and expenditures by the Surety shall be applied against the above penal sum and in reduction of the limit of liability of the Surety.

PROVIDED HOWEVER, that this bond is executed by the Surety and accepted by the Obligee subject to the following expressed conditions:

1. A Reorganization under Chapter 11 of the US Bankruptcy Code by the Principal shall not constitute an event of default recoverable under this bond if they continue to perform their obligations under the Contract (including but not limited to timely payment of all amounts due under the contract), and provided that Principal assumes the contract within 30 days of the filing of any bankruptcy petition.

2. This bond is for the term beginning __________ and expiring __________.**The bond will automatically renew for a one year period upon the expiration date** set forth above and upon each anniversary of such date, unless at least thirty (30) days prior to such expiration date, or prior to any anniversary of such date, Surety provides written notice to both the Obligee and Principal of its intention to non-renew this bond.

3. Neither non-renewal by the Surety, nor failure, nor inability of the Principal to file a replacement bond shall constitute a default by the Principal and entitle the Obligee to recover the full amount under this bond.

4. Surety's liability under this bond and all continuation certificates issued in connection therewith shall not be cumulative and shall in no event exceed the amount as set forth in this bond or in any additions, riders, or endorsements properly issued by the Surety as supplements thereto.

5. No claim, action, suit or proceeding, except as herein set forth, shall be had or maintained against the Surety on this bond unless same be brought or instituted and process served upon the Surety within six months following the expiration of the original term of this bond, or extended term as provided herein.

In the event of conflict or inconsistency between the provisions of this Performance Bond and the provisions of the above Contract, the provisions of this Performance Bond shall control. The Obligee's acceptance of this bond and reliance upon it as security constitutes its acknowledgement and agreement as to the explicit terms stated herein under which it is offered and issued by the Surety.

Sealed with our seals and dated this ____DAY____________ day of ________MONTH__________________________ 20____.

WITNESS:	**DEV/PROJECT CO LLC:**
___________________________________	______________________________(SEAL)
(Name & Title)	(Signature)

____
____
(Name & Title)

WITNESS:

____
____
(Name & Title)

[SURETY] INSURANCE COMPANY

_________________________________(SEAL)
(Signature)

____
____
(Name & Title)

EXHIBIT C
"FORM OF SURETY BOND" – TEMPLATE 2

BOND NUMBER ____________________

INSURANCE COMPANY
POWER PURCHASE AGREEMENT BOND

KNOW ALL MEN BY THESE PRESENTS, That we ____ (hereinafter called "Principal"), and INSURANCE COMPANY authorized to do business in the State of ______________________ (hereinafter called "Surety") are held and firmly bound unto ____ (hereinafter called "Obligee") as Obligee, for such monetary amount as incurred by the Obligee, not to exceed the penal sum of ____($___________________) DOLLARS, good and lawful money of the United States of America, the payment of which, well and truly to be made, we do bind ourselves, our heirs, administrators, executors, successors, and assigns, jointly and severally, firmly by these presents.

WHEREAS the above bounded Principal has entered into a certain written Contract with the above named Obligee, effective the ________ day of ___________________,20____, for the ____ ________________ which Contract is hereby referred to and made a part hereof as fully and to the same extent as if copies at length were attached herein.

The obligation of this Performance Bond shall be null and void unless: (1) the above Contract is in writing, and has been fully executed by both the Principal and the Obligee; (2) the Principal is actually in default under the above Contract, and is declared by the Obligee thereafter to be in default; (3) the Obligee has performed all of the obligations of the Obligee under the Contract; and (4) the Obligee has provided written notice of the default to the Surety as promptly as possible, and in any event, within ten (10) days after such default.

The Surety, at the sole election and discretion of the Surety, may take any of the following actions:

1. With notice to the Obligee, provide financial assistance to the Principal to remedy any contractual default by the Principal; or

2. Undertake the completion of the above Contract by the Surety, through its agents or through independent contractors; or

3. Determine the amount for which the Surety may be liable to the Obligee, and as soon as practicable thereafter, tender payment thereof to the Obligee; or

4. Pay the full amount of the above penal sum in complete discharge and exoneration of this Performance Bond, and of all liabilities of the Surety relating hereto.

If the Surety so elects to act, all payments and expenditures by the Surety shall be applied against the above penal sum and in reduction of the limit of liability of the Surety.

PROVIDED HOWEVER, that this bond is executed by the Surety and accepted by the Obligee subject to the following expressed conditions:

5. A Reorganization under Chapter 11 of the US Bankruptcy Code by the Principal shall not constitute an event of default recoverable under this bond if they continue to perform their obligations under the Contract.

6. This bond is for the term beginning __________ and expiring __________.The bond will automatically renew for a one year period upon the expiration date set forth above and upon each anniversary of such date, unless at least thirty (30) days prior to such expiration date, or prior to any anniversary of such date, Surety provides written notice to both the Obligee and Principal of its intention to non-renew this bond.

7. Neither non-renewal by the Surety, nor failure, nor inability of the Principal to file a replacement bond shall constitute a default by the Principal recoverable by the Obligee under this bond.

8. Surety's liability under this bond and all continuation certificates issued in connection therewith shall not be cumulative and shall in no event exceed the amount as set forth in this bond or in any additions, riders, or endorsements properly issued by the Surety as supplements thereto.

9. No claim, action, suit or proceeding, except as herein set forth, shall be had or maintained against the Surety on this bond unless same be brought or instituted and process served upon the Surety within six months following the expiration of the original term of this bond, or extended term as provided herein.

In the event of conflict or inconsistency between the provisions of this Performance Bond and the provisions of the above Contract, the provisions of this Performance Bond shall control. The Obligee's acceptance of this bond and reliance upon it as security constitutes its acknowledgement and agreement as to the explicit terms stated herein under which it is offered and issued by the Surety.

Sealed with our seals and dated this ________________ day of ________________________________ 20____.

WITNESS: **PRINCIPAL:**

____	________________________________(SEAL)
	(Signature)
(Name & Title)	
	____
	(Name & Title)
WITNESS:	**INSURANCE COMPANY**
____	________________________________(SEAL)
(Name & Title)	(Signature)
	____
	(Name & Title)

Exhibit D

Production Model Variables and Methodology

The Production Model shall include:

A. As Built Facility Parameters;

B. Solar Module Manufacturer PAN file;

C. Inverter Manufacturer OND file;

D. Meteorological Station Data (average of the on-site metering equipment):

a. Global Horizontal Irradiance;
b. Diffuse Irradiance;
c. Plane of Array Irradiance;
d. Albedo Irradiance;
e. Ambient Air Temperature; and
f. Wind Speed.

E. Annual solar panel degradation

The methodology for the Production Model shall be established by the Seller's lender's independent engineer, using the engineer's standard methodology to calculate expected production during each Availability Day. The Production Model shall use the factors above, plus other relevant factors to produce the most accurate results. The Production Model shall be based on solar generation industry standard estimation software, which as of the time of agreement is PVsyst.

EXHIBIT E

Form of
GUARANTY AGREEMENT

This Guaranty Agreement ("Guaranty") is made and entered into as of the th day of ______________, 20___ by ______________, a ____________ corporation ("Guarantor"), in favor of **LOUISVILLE GAS AND ELECTRIC COMPANY**, a Kentucky corporation, and **KENTUCKY UTILITIES COMPANY**, both a Kentucky and a Virginia corporation, (collectively referred to as the "Beneficiary").

RECITALS:

F. Guarantor is an affiliate of Rhudes Creek Solar, LLC, a Delaware limited liability company ("Counterparty").

G. Beneficiary and Counterparty are parties to that certain Power Purchase Agreement dated as of November __, 2019 (as may be amended, the "Agreement").

H. Beneficiary is obligated to provide certain credit support to Beneficiary pursuant to the Agreement, and Guarantor has agreed to provide such credit support pursuant to this Guaranty.

NOW, THEREFORE, with reference to the above recitals and in reliance thereon, and for other valuable consideration, the mutuality, receipt and sufficiency of which is hereby acknowledged, and intending to be legally bound hereby, Guarantor agrees with Beneficiary as follows:

1. General. Subject to the provisions of sections 2 and 3 below, Guarantor hereby absolutely and unconditionally guarantees to Beneficiary, its successors and permitted assigns, the due and punctual payment by Counterparty of all amounts which are due or which may hereafter become due to Beneficiary under or pursuant to the Agreement (including, but not limited to, amounts or damages relating to indemnity, default, breach or termination). Any payments made by Guarantor to Beneficiary hereunder shall be made in the lawful money of the United States in the amount(s) required under the Agreement no later than five (5) business days following Beneficiary's delivery to Guarantor of written notice of Counterparty's failure to make payments when due under the Agreement and request for payment under this Guaranty.

2. Maximum Liability. THE MAXIMUM AGGREGATE LIABILITY OF GUARANTOR HEREUNDER IS ______________________.

3. Termination. THE TERMINATION DATE OF THIS GUARANTY IS ________________. This Guaranty will continue in full force and effect until such date unless earlier terminated by either party providing 10 days' notice to the other party; provided however, that termination of this Guaranty shall not affect the validity or enforceability of this Guaranty with respect to (1) any guaranteed obligation incurred or arising prior to the termination of this Guaranty, and (2) any extensions or renewals of,

interest accruing on, or fees, costs or expenses (including attorney's fees) incurred with respect to, such pre-termination obligations on or after termination.

4. No Conditions. This Guaranty is a direct, unconditional, absolute and continuing guaranty of payment (not of collection). Without limiting the generality of the foregoing, Guarantor agrees that this Guaranty is not conditioned upon its receipt of any type of notice except as set forth in Section 1 (including, but not limited to, notice of acceptance of this Guaranty and notice of any sales transactions), and Guarantor hereby waives any right it may otherwise have to same.

5. No Discharge. None of the following shall operate to discharge Guarantor:

5.1 Any modification of the Agreement between Beneficiary and Counterparty;

5.2 Beneficiary's acceptance of any instrument in substitution for any claim or debt;

5.3 Any renewal, extension, modification or substitution of or for any instrument;

5.4 Any leniency or failure to pursue collection by Beneficiary with respect to the Counterparty or Guarantor;

5.5 Any release or impairment of collateral, if any, which secures payment of the Counterparty's obligations to Beneficiary;

5.6 The inclusion by any subsequent separate agreement or by any amendment of this Guaranty at a later date of additional guarantors of the obligations guaranteed hereunder; or the subsequent release of any of same; or

5.7 Any delay of Beneficiary in the exercise of, or failure to exercise, any rights hereunder or under the Agreement, or any single or partial exercise by Beneficiary of any right, remedy or power hereunder or under the Agreement.

6. Restoration. If at any time, any payment made by Counterparty to Beneficiary pursuant to the Agreement is rescinded or must be otherwise restored upon the insolvency, bankruptcy, or reorganization of Counterparty, the Guarantor's obligations hereunder with respect to such payment shall be reinstated at such time as though such payment had not been made.

7. Attorney's Fees. The Guarantor will pay for all Beneficiary's costs incurred in enforcing its rights under this Guaranty, by legal process or otherwise, including, but not limited to, Beneficiary's reasonable attorney's fees.

8. Assignment. This Guaranty is assignable by Beneficiary shall inure to the benefit of Beneficiary, its successors and assigns.

9. Validity. Guarantor represents and warrants to Beneficiary that this Guaranty has been duly executed and delivered by Guarantor and constitutes the legal, valid and

binding obligation of Guarantor, enforceable against Guarantor in accordance with its terms, except to the extent that such enforceability may be limited by applicable bankruptcy, insolvency, reorganization and similar laws affecting creditors' rights generally, and subject to general principles of equity, including the discretion of a court in granting equitable remedies.

10. Governing Law. Legal rights and obligations hereunder shall be determined in accordance with the laws of the Commonwealth of Kentucky.

11. Defenses. Guarantor waives defenses arising out of (i) the bankruptcy, insolvency, dissolution or liquidation of Counterparty, (ii) ultra vires, lack of capacity, due authorization or authority of Counterparty or its signatories, and (iii) lack of lack of due formation, existence or good standing of Counterparty and any other defenses expressly waived herein or in the Transactions or Confirmations. The Guarantor will not exercise any rights which it may have or acquire by way of subrogation, contribution, indemnity or similar against Counterparty until all amounts due to the Beneficiary hereunder shall have been paid in full.

12. Severability. Every provision of this Guaranty is intended to be severable. If any term or provision hereof is declared to be illegal or invalid for any reason whatsoever by a court of competent jurisdiction, such illegality or invalidity shall not affect the balance of the terms and provisions hereof, which terms and provisions shall remain binding and enforceable.

13. Notices. All notices, requests, demands and other communications required or permitted to be made or given under this Guaranty shall be in writing and shall be deemed to have been given (i) on the date of personal delivery, (ii) on the date of deposit in the U.S. Mail, by registered or certified mail, postage prepaid, or (iii) on the date of delivery to a reputable overnight courier service, in each case addressed to the parties as follows:

If to Guarantor, to: ________________________

If to Beneficiary, to: Louisville Gas and Electric Company/Kentucky Utilities Company
220 West Main Street, 7th Floor
Louisville, Kentucky 40202
Attn: Manager, Credit and Contract Administration
Facsimile: (502) 627-3950

Any party may change its address for receiving notice by written notice given to the other as set forth above.

14. Entire Agreement/No Amendment. The Guaranty constitutes the entire agreement and understanding of the parties hereto respecting its subject matter and supersedes all prior written and contemporaneous oral agreements, representations and understandings relating to its subject matter. No term hereof may changed, waived, discharged or terminated unless by an instrument signed by the party against whom enforcement is sought.

IN WITNESS WHEREOF, Guarantor has executed this Guaranty on the date shown below.

____
GUARANTOR

By: ______________________________
Its: ______________________________
Date: ______________________________

AMENDMENT NO. 1 TO POWER PURCHASE AGREEMENT

THIS AMENDMENT NO.1 TO POWER PURCHASE AGREEMENT (this "Amendment") **is** entered into, effective as of January 10, 2020 (the "Amendment Effective Date") by and among (i) **Rhudes Creek Solar, LLC** ("Seller"), a Delaware limited liability company with a principal place of business at c/o ibV Energy Partners LLC, 777 Brickell Ave., Suite 500, Miami, FL 33131, (ii) **Louisville Gas and Electric Company** ("LG&E"), a Kentucky corporation with a principal office at 220 West Main Street, Louisville, Kentucky 40202, and (iii) **Kentucky Utilities Company** ("KU"), a Kentucky and Virginia corporation with its principal office at One Quality Street, Lexington, Kentucky 40507. LG&E and KU are hereinafter referred to collectively as the "Buyers." Seller and Buyers are sometimes together referred to below as the "Parties."

WHEREAS, the Parties entered into a Power Purchase Agreement (the "Existing Agreement") on November 21, 2019; and

WHEREAS, since entering into the Existing Agreement, the Parties have identified typographical errors in the Existing Agreement and desire to amend the Existing Agreement to correct such errors as set forth below.

NOW THEREFORE, intending to be legally bound and for good and valuable consideration, the receipt of which is hereby acknowledged, the Parties do agree as follows:

1. **Amendments.** The Existing Agreement is hereby amended effective as of the Amendment Effective Date as follows:

    a. The headers on pages i, ii, and iii of the Existing Agreement are revised by deleting the words "RS Draft."

    b. Section 1.2(B) of the Existing Agreement is revised by deleting the second instance of the word "and." (Specifically, the word to be deleted is at the end of the second line of Section 1.2(B) of the executed Existing Agreement.)

    c. The definition of "Availability Underperformance Notice" in Section 1.4 of the Existing Agreement is revised by replacing the reference to Section 8.3(A) with a reference to Section 8.3(B).

    d. The definition of "Commercial Operation" in Section 1.4 of the Existing Agreement is revised by replacing the reference to Section 4.1 with a reference to Section 4.2.

    e. The definition of "Early Termination Date" in Section 1.4 of the Existing Agreement is revised by replacing the reference to Section 12.4(B) with a reference to Section 12.4(A).

    f. The definition of "Test Energy" in Section 1.4 of the Existing Agreement is revised by replacing the reference to Section 4.2 with a reference to Section 4.3.

    g. Section 8.1(B) of the Existing Agreement is revised by replacing the reference to Section 4.2 with a reference to Section 4.3.

    h. Section 8.3(D) of the Existing Agreement is revised by replacing both references to Section 8.3(A) with references to Section 8.3(B).

i. Section 9.1(C) of the Existing Agreement is revised by replacing the reference to Section 4.2 with a reference to Section 4.3.

j. Section 10.2(C) of the Existing Agreement is revised by replacing the reference to Section 4.2 with a reference to Section 4.3.

2. **Status of Contract.** As amended hereby, the Existing Agreement shall continue in full force and effect.

3. **Miscellaneous.** This Amendment shall be governed and construed in accordance with the laws of the Commonwealth of Kentucky notwithstanding its conflict of laws rules or any principles that would trigger the application of any other law. This Amendment shall be binding upon and inure to the benefit of the Parties and their respective successors in interest, legal representatives, and assigns permitted under the Existing Agreement. This Amendment may be executed in two or more counterpart copies of the entire document or of signature pages to the document, each of which may have been executed by one or more of the signatories hereto and thereto and deliveries by mail, courier, telecopy or other electronic means, but all of which taken together shall constitute a single agreement, and each executed counterpart shall have the same force and effect as an original instrument. This Amendment constitutes the sole and entire agreement of the Parties with respect to the subject matter contained herein, and supersedes all prior and contemporaneous understandings, agreements, representations and warranties, both written and oral, with respect to such subject matter.

IN WITNESS WHEREOF, the parties hereto have executed this Amendment on the date(s) below written, but effective as of the Amendment Effective Date.

[remainder of this page intentionally left blank]

Seller:

Rhudes Creek Solar, LLC

By: ______________________

Name: Timothy C. Kim

Title: President

Date: January 13, 2020

Buyer:

Louisville Gas and Electric Company

By: ______________________

Name: ____________________

Title: ______________________

Date: ______________________

Kentucky Utilities Company

By: ______________________

Name: ____________________

Title: ______________________

Date: ______________________

Seller:

Rhudes Creek Solar, LLC

By: ____________________

Name: ____________________

Title: ____________________

Date: ____________________

Buyer:

Louisville Gas and Electric Company

By: David S. Sinclair

Name: David S. Sinclair

Title: VP Energy Supply + Analysis

Date: 1-10-20

JD

Kentucky Utilities Company

By: David S. Sinclair

Name: David S. Sinclair

Title: VP Energy Supply + Analysis

Date: 1-10-20

JD

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	**CASE NO. 2020-00349**
ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	**CASE NO. 2020-00350**

REBUTTAL TESTIMONY OF

JOHN J. SPANOS

ON BEHALF OF

KENTUCKY UTILITIES COMPANY

AND LOUISVILLE GAS & ELECTRIC COMPANY

Filed: April 12, 2021

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. ARE YOU ASSOCIATED WITH ANY FIRM?

A. Yes. I am President of the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. In my rebuttal testimony, I respond to the depreciation-related recommendations of the Office of the Attorney General ("AG") and Kentucky Industrial Utility Customers ("KIUC") witness Lane Kollen, the Kroger Company ("Kroger") witness Justin Bieber and United States Department of Defense and all other Federal Executive Agencies ("DoD/FEA") witness Brian C. Andrews. There are two specific depreciation issues I will address. The first is the life spans for some of the Companies' coal-fired steam power plants. All three witnesses have recommended longer life spans than those I have proposed, which, for the plants in question, all recommend maintaining the current life span for each facility. Given the numerous factors influencing the economics of operating coal-fired generation, I do not believe that their proposals to maintain the life spans for these facilities are appropriate. In addition, each witness recommends an alternative approach to recovery that is not consistent with matching the recovery of the asset over their remaining life. Mr. Bieber recommends maintaining past life spans and parameters and then developing a regulatory asset for the net book value after retirement. Mr. Kollen recommends creating a Retirement Rider for each plant for 25-years beyond the retirement of each unit. Mr. Andrews only addresses Kentucky Utilities E.W. Brown Unit 3 and recommends recovery to 2035 which was the past retirement date of the unit. Each of these proposals are inappropriate as they are inconsistent with GAAP and regulatory principles and will result in intergenerational inequity.

II. DEPRECIATION CONCEPTS AND INTERGENERATIONAL EQUITY

Q. WHAT IS DEPRECIATION?

A. Depreciation is defined in the FERC Uniform System of Accounts ("USofA"):

> 12. *Depreciation*, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.

Q. WHAT IS THE OBJECTIVE OF DEPRECIATION?

A. The objective of depreciation is to allocate, in a systematic and rational manner, the full cost of an asset (original cost less net salvage) over its service life. The USofA requires this in General Instruction 22-A:

> *Method*. Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value[1] of depreciable property over the service life of the property.

Thus, the USofA confirms that depreciation represents the allocation of the full costs of a company's assets (original cost less any net salvage) over their service lives – that is, over the period of time the assets are providing service. Costs are allocated over the service lives of the assets so that customers pay for the costs of the assets that provide them service. Current customers should not pay for the costs of assets that have already

[1] The USofA defines service value as the original cost less net salvage.

been retired or those not yet in service. Similarly, future customers should not have to pay for the costs of assets that are no longer in service because current customers pay too little for their service.

Q. WHAT IS THE DEFINITION OF SERVICE LIFE?

A. The USofA defines service life as follows:

> 36. *Service life* means the time between the date electric plant is includible in electric plant in service, or electric plant leased to others, and the date of its retirement. If depreciation is accounted for on a production basis rather than on a time basis, then service life should be measured in terms of the appropriate unit of production.[2]

As discussed previously, one of the issues in this proceeding is the life spans of various generating units. Thus, the service life for an asset at these plants is the time from the asset's installation until its retirement date. Therefore, the USofA definition requires the costs of the assets at each generating unit to be recovered through depreciation by the date of retirement which has been updated in the depreciation studies. The proposals of other parties – whether to use longer lives or to maintain current deprecation rates which are based on longer lives – will not achieve this objective and will instead recover costs after some of the Company's plants are retired.

Q. WHAT IS THE CONCEPT OF "INTERGENERATIONAL EQUITY"?

A. Intergenerational equity is a ratemaking principle in which customers receiving the benefit from the use of an asset (e.g., from electric utility property used to provide electric service) are the same customers who pay the cost of that asset. There are actually two related concepts when considering intergenerational equity as it pertains to depreciation. The first is the inequity that results from a situation in which customers pay for assets

[2] FERC USofA, Definition 36.

from which they receive no service. For example, if a power plant is retired before becoming fully depreciated, then customers subsequent to the retirement will have to pay for an asset from which they are not receiving service. This is inequitable, as one generation of customers bears the cost of an asset from which they receive no service (and that provided service to an earlier generation). The second concept is instead related to the distribution of depreciation charges over the life of an asset. For example, if depreciation expense is higher in the earlier years of an asset's life and lower in later years (or vice versa), this could also be considered inequitable because one generation of customers pay a higher share than a different generation.

In my view, the first concept related to intergenerational equity is more harmful to customers than the second. That is, there is a greater degree of inequity that results from a customer paying for an asset that only provided service to other generations of customers – and not to him or her – than results from one generation paying somewhat more or less than a previous generation for the same asset. Additionally, I would add that depreciation is necessarily a forecast of future events (such as the actual retirement date of a power plant) that will occur many years in the future. It is therefore nearly impossible to perfectly allocate costs equally over the lives of a utility company's entire asset base.

III. THE LIFE SPAN METHOD

Q. PLEASE EXPLAIN THE CONCEPT OF A "LIFE SPAN."

A. For certain types of facilities, referred to as "life span property," all assets at the facility will be retired concurrently. A textbook example of a life span property is a power plant. When the plant is retired, all assets at the plant will be retired (whether installed the day the plant went into service or were placed into service recently). The retirement of the entire facility is referred to as the "final retirement" or "terminal retirement." The period of time from the original year the plant was placed into service to the final retirement is the "life span" of the facility.

Not all assets at a facility will be retired as final retirements. Some components of life span property will be replaced during the life span of the overall facility. When such assets are retired or replaced, they are referred to as "interim retirements." New assets installed subsequent to the original installation of the facility up to the date of final retirement are referred to as "interim additions." Interim retirements need not be minor items. For example, a utility will replace boiler feed pumps at its coal-fired power plants prior to the final retirement of the facilities. The retired feed pumps will be interim retirements and the new boiler feed pumps that replace the retired pumps will be interim additions.

Q. HOW IS DEPRECIATION DETERMINED FOR LIFE SPAN PROPERTY IN ORDER TO MEET THE OBJECTIVE OF DEPRECIATION YOU SET FORTH ABOVE?

A. The life span method allows for costs to be equitably allocated over the life span of the facility as well as over the lives of interim retirements. When the life span method is used, a "probable retirement date" is estimated[3]. The probable retirement date represents the point in time in the future when it is most probable that the life span facility will be retired. The use of a probable retirement date allows depreciation to be calculated so that each vintage of assets at the facility will be depreciated by the time of the estimated retirement date. As a result, both the original installation and interim additions that have

[3] NARUC, *Public Utility Depreciation Practices*, 1996, p. 141.

occurred to date are recovered over the appropriate period of time.

The life span method also allows for the estimation of interim retirements. This is most commonly achieved with the use of "interim survivor curves," which estimate what percentage of plant will be retired each year. However, in some instances, such as interim retirements of larger assets such as ash ponds, it is necessary to separately identify large interim retirements and depreciate these assets over their expected useful life.

IV. LIFE SPANS OF COAL-FIRED POWER PLANTS

Q. WHAT HAVE YOU PROPOSED FOR THE LIFE SPANS OF THE COMPANY'S COAL-FIRED POWER PLANTS?

A. For the Company's coal plants, the life spans I have proposed are consistent with the life spans used for the Company's current depreciation rates, with the exception of seven units. The Depreciation Studies reflect the changed economic expectations for Brown Unit 3, Ghent Unit 4, all four units at Mill Creek, and Trimble County Unit 1. For each of these units, the proposed life spans are between 1 and 8 years shorter than the current life spans, except Mill Creek Unit 3 which has a longer life span by 1 year.

Q. HOW ARE LIFE SPANS TYPICALLY ESTIMATED?

A. A power plant is typically retired as the result of an economic decision. As a plant ages and becomes more expensive to operate, and as new technologies become more efficient and economical relative to existing generation, it eventually becomes economical to replace the existing plant. Also, in many cases there are environmental regulations that determine the retirement date. The retired plant may be able to physically operate for a longer period of time, but it would be a more costly option to keep the plant in service.

Thus, the process of estimating the life spans of a utility's power plants is more than determining how long a plant could physically last. It must also consider the economic decision as to when to replace the plant with newer generation. Factors considered in determining life span estimates include the life spans and experience of other similar facilities for the Company and others in the industry; an understanding of technological, environmental, regulatory and operational changes that could impact the life of a facility; and an understanding of other factors that impact the economics of operating a facility, such as fuel prices for both the plant at issue and for competing sources of generation.

Q. IN ESTIMATING THE LIFE SPANS FOR LG&E AND KU'S FACILITIES, WERE THESE TYPES OF FACTORS CONSIDERED?

A. Yes. The economic estimation of life spans for the Company's facilities incorporated these types of factors. The Companies performed their own analyses of the most appropriate life span for each facility, which is discussed by Witness Bellar and is included in Exhibit LEB-2 entitled "Analysis of Generating Unit Retirement Years." Importantly, for each of the plants at issue, the Company has announced the expected retirement of these facilities which align with the proposed retirement dates in the depreciation study. I also performed an independent review based on my experience and knowledge of other facilities in the industry. In my judgment, the recommended retirement dates in the depreciation studies represent the most reasonable probable retirement dates for each facility.

I do not believe it would be appropriate to maintain the current life spans of all of the Company's coal-fired generating facilities. Doing so would risk having too long of life spans, resulting in intergenerational inequity. This is particularly true for units such as Mill Creek Units 1 and 2 and E.W. Brown Unit 3, for which continuing to use the same life span would result in recovering the costs of these facilities beyond the date at which the units are expected to be retired. The Company has publicly stated that these three units have projected retirements and have issued proposals for replacement capacity after having made investment decisions with regards to compliance with the Environmental Protection Agency ("EPA") for Effluent Limitation Guidelines ("ELG") regulations that assume retirement for each unit.

Q. WHAT HAVE MR. KOLLEN, MR. BIEBER AND MR. ANDREWS PROPOSED FOR THE LIFE SPANS OF THE COMPANY'S COAL PLANTS?

A. All have proposed to increase the life spans for many of the Company's coal plants from those recommended in the Depreciation Studies. Mr. Kollen disregards Company specific information related to the retirement of coal plants, specifically the expectations of the Mill Creek Unit 1 and 2 and Brown Unit 3, and then creates an arbitrary 25-year Retirement Rider after the plants are retired to establish a deferred recovery of the net book value. Mr. Bieber implicitly recommends maintaining the same retirement dates of the coal plants based on his plan to maintain the current depreciation rates. Mr. Andrews accepts the retirement dates in the study for most facilities and only recommends the currently approved life span of E.W. Brown Unit 3.

Q. WHAT ARE THE BASES OF THEIR PROPOSALS?

A. None of the other parties provide specific support for using retirement dates that are inconsistent with the outlook for Mill Creek Unit 1, Mill Creek Unit 2 and Brown Unit 3. Instead, the basis for their proposals appears to only be to reduce depreciation expense. None of the parties' challenge whether the facilities will retire at the proposed retirement date; they instead recommend a recovery pattern that is inconsistent with the actual lives of these facilities. Mr. Kollen takes his proposal even further by creating an arbitrary 25-year recovery after each plant was previously determined to be retired, not the current plan to retire. Thus, they each disregard Company plans, current industry activity and trends in new generation.

Q. HAVE ANY OF THE PARTIES CHANGED THE DECOMMISSIONING COST COMPONENT IN THEIR ANALYSIS BY CHANGING THE LIFE SPAN DATE?

A. No. The decommissioning cost component in the depreciation studies are based on the date of retirement established in the studies; therefore, if the parties change/increase the life span date then the cost to decommission will be higher at that time. None of the other parties have recalculated that cost to decommission for each unit or if unit costs were calculated the amounts are not updated correctly based on the parties' changes to the life span date.

Q. IS IT REASONABLE TO EXPECT THE LIFE SPANS OF THE COMPANY'S COAL PLANTS TO CHANGE OVER TIME?

A. Yes. In my judgment, particularly based on the experience of both LG&E and KU as well as others in the industry, it is not only appropriate to revise the life spans of the Company's coal plants, but it is also consistent with the experience of other utilities. Across the country, many coal plants have been retired earlier than expected and many have had shorter life spans than currently approved. Indeed, this can be seen in the Companies' experience. Since 2015, the Companies have retired multiple coal units including the retire of Brown Units 1 and 2 in 2019 and Cane Run Units 4, 5 and 6 in 2015. The Company also retired the Pineville plant in 2002, Tyrone units in 2007 and 2013, Green River units in 2003 and 2015, and Cane Run Units 1, 2 and 3 in 1985. Most of these had a life span of less than 60 years, as can be seen in the table below.

Table 1: Life Spans of Retired or Planned to Be Retired LG&E and KU Coal-Fired Power Plants

Unit	In-Service Year	Retirement Year*	Life Span
Cane Run Unit 1	1954	1985	31
Cane Run Unit 2	1956	1985	29
Cane Run Unit 3	1958	1985	27
Pineville	1951	2002	51
Green River Unit 1	1950	2003	53
Green River Unit 2	1950	2003	53
Tyrone Unit 1	1947	2007	60
Tyrone Unit 2	1948	2007	59
Tyrone Unit 3	1953	2013	60
Cane Run Unit 4	1962	2015	53
Cane Run Unit 5	1966	2015	49
Cane Run Unit 6	1969	2015	46
Green River Unit 3	1954	2015	61
Green River Unit 4	1959	2015	56
Brown Unit 1	1956	2019	63
Brown Unit 2	1963	2019	56

*Retirement year represents the year unit no longer was generating electricity. This is not the same date assets were removed from service as shown in the depreciation study.

As can be seen in the table, the plants that the Company has retired have had shorter life spans or comparable life spans for the facilities that are at issue in this case. Further, the average life span of these retired plants was approximately 50 years, which is even shorter than the life spans I have proposed for most of the Company's remaining coal-fired power plants and specifically Mill Creek Unit 1, Mill Creek Unit 2 and Brown Unit

3. Additionally, while some of the older plants have had longer life spans, the Company's newer plants have tended to have shorter experienced life spans, which is consistent with the experience of many in the industry. For example, all of the plants in the table above that were installed since 1960 have had life spans less than 60 years.

The shorter life spans for plants built over the last 40 years is due to many additional factors, such as the influx of renewable energy sources, lower natural gas prices, environmental regulations and efficiencies of coal. In fact, over the last 5 – 7 years, the average age of generating facilities that have been retired has been less than 50 years.

Q. WHY HAVE NEWER COAL-FIRED POWER PLANTS TENDED TO HAVE MORE RAPIDLY CHANGING CIRCUMSTANCES THAN OLDER PLANTS?

A. As I noted above, three of the primary factors that have resulted in the retirement of coal-fired power plants have been new technologies of generation (both efficient gas combined cycle plants and renewables), low fuel prices for natural gas generation and environmental regulations. The impact of these factors on existing coal-fired generation became significant in the mid-to-late 2000s, whereas these factors did not have as much of an impact prior to this time period. Thus, a power plant installed in the 1940s would have been in service for 60 years or more before these factors began to significantly impact the economics of the plant. This allowed older plants to attain longer life spans. However, a plant placed in service in the 1970s or 1980s would be much younger (20 or 30 years of age) in the mid-to-late 2000s, which has tended to, on average, result in shorter life spans for newer coal-fired power plants.

Q. ARE THERE COMPARABLE EXAMPLES OF POWER PLANTS RETIRING EARLIER THAN EXPECTED IN OTHER JURISDICTIONS?

A. Yes. There are a number of examples of power plants of the same vintage as the Company's remaining fleet of coal plants that either have retired or are planned to be retired that had or will have shorter life spans than those proposed by the other parties. The Company's three generating units that are at issue in this proceeding have all been installed since 1971 (Brown Unit 3 is the oldest coal-fired unit expected to remain in service beyond 2020). There have been a number of plants installed since 1971 that either have been or are planned to be retired. For example, Nevada Power has retired its Reid Gardner plant and Navajo plant (of which it is a co-owner) by the end of 2019. The life spans of the six units at these plants (each has three units) range from 37 to 48 years. Indianapolis Power & Light retired its Harding Street Station Units 1 and 2 in 2016, resulting in a 43-year life span. MidAmerican Energy closed its Neal Unit 2 plant in 2015, resulting in a life span of 43 years. Public Service Company of Oklahoma's Northeastern Unit 4 plant was retired in 2016 and had a life span of 36 years. The Saint John's River Power Park ("SJRPP") plant was retired in 2018. The two units at this plant had life spans of 30 and 31 years.

Additionally, the Boardman plant in Oregon was retired in 2020, which will result in a 40-year life span. Duke Energy Progress's Asheville plant was shut down by end of 2019, resulting in a 48-year life span. Public Service Company of Oklahoma plans to retire its Northeastern Unit 3 plant in 2026, resulting in a life span of 46 years. These are just a few examples of coal-fired units being retired consistently with the plans of the Company's generating units.

Q. HAS THERE BEEN RECENT ANNOUNCEMENTS OF COAL FIRED PLANT RETIREMENTS IN KENTUCKY?

A. Yes. Tennessee Valley Authority has announced the closure of units at their Paradise and Bull Run facilities. Paradise Units 1 and 2 were retired in 2017 and Paradise Unit 3 was retired in February 2020. The three units had a life span between 50 and 54 years. The Bull Run facility will be retired by December 2023 and will have a life span of 56 years.

Q. CAN YOU SUMMARIZE THE FUNDAMENTAL FLAWS OF THE OTHER PARTIES' DEPRECIATION POSITIONS?

A. Yes. First, each party selects a life span for all units which does not consider that the Company has announced expectations to retire many of these facilities, nor do their proposals appear to incorporate any planning for meeting generating requirements or unit capabilities. Second, each party's calculations just extend the remaining lives to a longer life span without properly calculating the interim survivor curve and net salvage components. A longer life span results in more interim retirements and more net salvage, which requires more depreciation expense than what they have proposed. Finally, each party has attempted to make depreciation expense a results-oriented exercise without truly following the concept and definition of depreciation. Their proposals will not recover the Company's costs over their service lives and instead will result in future customers paying the costs of assets that will have been removed from service.

V. RECOVERY STANDARDS FOR GENERATING UNITS

Q. WHAT IS THE ISSUE IN THIS SECTION OF YOUR TESTIMONY?

A. In this section I address the other parties' proposals to depreciate the costs for generating units over a period of time much longer than the actual service lives of these units. In the case of Mr. Kollen, the additional 25-year Retirement Rider after the plants have been retired will also be addressed.

Q. HOW WILL YOU ADDRESS THIS ISSUE?

A. First, I will explain important depreciation concepts, and specifically explain that the goal of depreciation is to allocate the costs of the Company's assets over their service lives. I will then address specific proposals of each party.

Q. YOU HAVE PREVIOUSLY EXPLAINED THAT THE OBJECTIVE OF DEPRECIATION IS TO ALLOCATE THE COSTS OF THE COMPANY'S ASSETS OVER THEIR SERVICE LIVES. WHAT IS THE DEFINITION OF SERVICE LIFE?

A. The FERC Uniform System of Accounts (USofA) defines service life as follows:

> 36. *Service life* means the time between the date electric plant is includible in electric plant in service, or electric plant leased to others, and the date of its retirement. If depreciation is accounted for on a production basis rather than on a time basis, then service life should be measured in terms of the appropriate unit of production.[4]

Q. WHAT IS THE DEFINITION OF COST OF REMOVAL:

A. The FERC Uniform System of Accounts (USofA) defines cost of removal as follows:

> 10. Cost of Removal means the cost of demolishing, dismantling, tearing down or otherwise removing utility property including the cost of transportation and handling of incidental thereto. It does not include the cost of removal activities associates with assets retirement obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation[5].

[4] FERC Uniform System of Accounts, Definition 36
[5] FERC Uniform System of Accounts, Definition 10

Q. DOES MR. KOLLEN'S POSITION RELATED TO HOW TO HANDLE DECOMMISSIONING COSTS MEET THIS DEFINITION?

A. No. The cost to remove or demolish a generating facility is part of the service value of the asset and should be recovered over the life of the asset. There is nothing in any depreciation text that suggests a deferral of these costs to a date into the future where future customers should pay for these costs that they did not receive benefit of the asset.

Q. THE DEFINITION REFERENCES THE END OF AN ASSET'S SERVICE LIFE AS THE "DATE OF ITS RETIREMENT." CAN YOU ADDRESS THE CONCEPT OF RETIREMENT FURTHER?

A. Yes. The retirement of an asset is the point in time when the asset is removed from providing service to customers. NARUC's *Public Utility Depreciation Practices* defines retirement as follows:

> Retirement: The sale, abandonment, distribution, or withdrawal of assets from service.[6]

NARUC goes on to explain that the retirement of an asset can occur due to a number of reasons (emphasis is added):

> The sole reason for concern about depreciation is that all plant devoted to the pursuit of a business enterprise will ultimately reach the end of its useful life. Several factors cause property to be retired. They include:
>
> 1. Physical Factors
>   a. Wear and Tear
>   b. Decay or deterioration
>   c. Action of the elements and accidents
> 2. Functional Factors
>   a. Inadequacy
>   b. Obsolescence
>   c. Changes in the art and technology
>   d. Changes in demand
>   e. Requirements of public authorities

[6] NARUC, *Public Utility Depreciation Practices*, 1996, p. 324

f. Management discretion
3. Contingent Factors
a. Casualties or disasters
b. Extraordinary obsolescence[7]

I emphasize "requirements of public authorities" because this is the factor leading to the retirement of many of the Company's units. This is a legitimate reason for retirement and should not be discounted or ignored – as other parties propose to do.

The Uniform System of Accounts has similar language in its definition of depreciation (emphasis added):

> 12. *Depreciation*, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and <u>requirements of public authorities</u>.

Thus, both NARUC and the USofA are clear that the requirements of public authorities are legitimate causes of retirement and must be given consideration when determining depreciation expense.

I would also like to point out that regulation is a legitimate cause of retirement, as has been the case for many units across the United States over the last seven years or so.

Q. CAN YOU EXPLAIN WHAT "REQUIREMENTS OF PUBLIC AUTHORITIES" MEANS?

A. Yes. In both the NARUC Manual and the USofA, requirements of public authorities

[7] NARUC, *Public Utility Depreciation Practices*, 1996, p. 14-15

refer to any type of requirement from an authority such as a state, local or federal government. One example is a public highway department may require a pole to be removed from its right-of-way, which would cause a retirement of a pole. Another example is state or federal regulations that result in the retirement of a power plant.

Q. WERE THERE OTHER FACTORS EXPLAINED BY THE COMPANY THAT DETERMINED A CHANGE IN LIFE SPANS FOR COAL-FIRED GENERATION?

A. Yes. Witness Bellar presents some of the factors that created the need to change life spans. These factors are presented in the Company's Generation Planning and Analysis in Exhibit LEB-2 which includes the impact of environmental regulations, fuel prices, cost of replacement generation, risks of failures and economics of maintenance costs.

Q. HOW HAS THE DEPRECIATION STUDY ADDRESSED THE DEPRECIATION OF THE ASSETS FOR EACH UNIT THAT HAS A RETIREMENT DATE SHORTER THAN PREVIOUSLY APPROVED ?

A. The study has determined depreciation designed to allocate the costs of these assets over their service lives. I have calculated depreciation to allocate the costs of each unit through the retirement date. This approach is fair to customers in that those who receive service from each unit will pay the costs of the facility, whereas future customers (who will have to pay for replacement generation) will not pay for a plant that is no longer providing service.

Q. WHAT ARE THE OTHER PROPOSALS?

A. Other parties in the case have recommended that the costs of units that did not change to be depreciated over their service lives but any unit that has changed since the last case will have an artificially longer life. For example, Trimble County Unit 2 is recovered over its service life, but the Mill Creek Units are recovered beyond their service life.

That is, each party has not proposed to depreciate the assets at any facility that has a changed life span over their service lives, but instead over a longer period of time. Effectively, each ignores that the outlook has changed for many facilities because they consider the result to be too high of depreciation expense. As I have explained, this is unfair to future customers who will not receive service from these generating units but will have to pay for the costs of both these plants and of replacement generation.

Q. HAVE RETIREMENT DATES ALWAYS BEEN THE SAME SINCE EACH UNIT WAS CONSTRUCTED?

A. No. The probable retirement date is reviewed and often revised as new information regarding the efficiency of the unit and cost benefit of alternative generation becomes available.

Q. YOU HAVE NOTED THAT DIFFERENT LIFE SPANS HAVE BEEN USED FOR SOME UNITS IN PREVIOUS DEPRECIATION STUDIES. HOW DOES A DEPRECIATION STUDY NORMALLY ADDRESS A CHANGE IN ESTIMATE?

A. Because depreciation is based on estimates of what will happen many years into the future, sometimes those estimates end up requiring adjustment as circumstances change. This is why depreciation studies are updated based on current information and service lives can be adjusted accordingly. That is, the standard and well-established process is to simply revise the estimates and adjust depreciation to recover the full cost of the Company's assets. This is what I have proposed and what ensures intergenerational equity and that the objective of depreciation is met.

However, this is not what the other parties have proposed. Other parties in this case have effectively decided to ignore Company plans related to revised retirement dates. Instead, they have proposed that they continue to be depreciated to a date beyond the date they provide service.

Q. DOES THE DEPRECIATION STUDY REPRESENT THE ACCELERATED RECOVERY OF COAL-FIRED GENERATION OR ACCELERATED DEPRECIATION?

A. Absolutely not. While the term "accelerated" is used by a number of witnesses, the recovery of the costs of coal-fired generation by revising life spans does not represent accelerated depreciation. Instead, it represents recovering these costs over the service life of units.

Accelerated depreciation refers to the recovery of more costs early in an asset's life compared to later in the asset's life. This has not occurred with coal fired generation. The Company's proposal is to depreciate the remaining costs – on a straight line basis – over the remaining period of time each unit will be in service. It is therefore most certainly not an accelerated recovery. Instead, it is the other parties' proposals that represent <u>deferred</u> recovery of the costs of the coal fired generation as they propose to recover these costs over a period of time that is 1 to 8 years longer than the units' service lives or in Mr. Kollen's proposal an additional 25 years after the extended life span period for each unit.

Q. PLEASE ADDRESS THE ARGUMENT THAT FUTURE CUSTOMERS SHOULD PAY THE COST OF THESE UNITS?

A. The proposals of each of the other party witnesses have set forth the argument that future customers should pay the costs of coal-fired generation beyond their service lives if the remaining net book value is deferred for recovery after they are retired. This argument is not consistent with any established regulatory concepts of which I am aware, and in particular is inconsistent with the objective of depreciation I have described earlier. It is well established that customers should pay the costs of the assets used to provide service, not the costs of assets that served previous generations.

One additional concept to keep in mind when evaluating this argument set forth by the other parties is that there will be electric generation that replaces the coal fired units. Future generations of customers will pay for the costs of these power plants. They therefore should not be saddled with incremental costs of paying for power plants that have already been retired.

Q. WHAT DO YOU CONCLUDE WITH REGARD TO THE LIFE SPANS OF THE COMPANIES' COAL-FIRED POWER PLANTS?

A. Based on a number of factors discussed above, the life spans used in the depreciation studies are most appropriate to use for the development of depreciation rates in this proceeding.

Q. PLEASE FURTHER COMMENT ON MR. KOLLEN'S POSITION RELATED TO DEPRECIATION?

A. Mr. Kollen has proposed depreciation expense that has no basis. First, he recommends life spans for generating facilities that do not match their expected useful lives. Second, he does not recalculate his overall depreciation expense including decommissioning costs when he recommends life spans that are not consistent with Company plans. Finally, he recommends recovering the net book value and decommissioning costs over an arbitrary 25-year period beyond his already longer life span for each unit. Per the Uniform System of Accounts, decommissioning costs as part of cost of removal should be recovered over the service life of the asset so waiting until the asset is retired is not appropriate or fair to all customers. These recommendations do not follow the concept of depreciation supported by all authoritative texts and requires future customers to pay for assets from which they did not receive any benefit.

Q. CAN YOU ADDRESS MR. BIEBER'S POSITION ON DEPRECIATION?

A. Yes. Mr. Bieber has proposed to maintain the current depreciation rates which are based on life spans, interim survivor curves and net salvage percentages that do not consider updated data or Company plans for steam facilities. Then he recommends creating a regulatory asset to recover any remaining net plant when the facilities are retired. Once again, this proposal does not follow the concept of depreciation and is not supported by any authoritative texts. This requires future customers to pay for assets from which they did not receive any benefit.

Q. CAN YOU FURTHER COMMENT ON MR. ANDREWS' CALCULATIONS RELATED TO DEPRECIATION EXPENSE FOR BROWN UNIT 3?

A. Yes. Witness Andrews does not challenge any of the methods or procedures utilized in either depreciation study; however, he recommends changing the life span utilized in the depreciation study for E.W. Brown Unit 3 and all remaining steam assets at the location. Consequently, Mr. Andrews utilizes a service life that does not match Company expectations and reduces expense in order to emphasize his results-oriented practice. There is no reason the recovery of the remaining Brown assets should be handled differently than other assets just because the expense is too high.

VI. CONCLUSION

Q. IN YOUR OPINION, ARE THE DEPRECIATION RATES SET FORTH IN YOUR DEPRECIATION STUDIES THE RATES THE KENTUCKY PUBLIC SERVICE COMMISSION SHOULD ADOPT IN THIS PROCEEDING FOR LG&E AND KU?

A. Yes, these rates appropriately reflect the rates at which the value of LG&E and KU's assets are being consumed over their useful lives. These rates are an appropriate basis for setting electric and gas rates in this matter and for the Companies to use for booking depreciation and amortization expense going forward.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
)
COUNTY OF CUMBERLAND)

The undersigned, **John J. Spanos,** being duly sworn, deposes and says that he is President for Gannett Fleming Valuation and Rate Consultants, LLC, that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John J. Spanos

John J. Spanos

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of April 2021.

Commonwealth of Pennsylvania - Notary Seal
MEGAN LYNN ECKRICH - Notary Public
Cumberland County
My Commission Expires Sep 16, 2023
Commission Number 1264513

(SEAL)
Notary Public Megan Lynn Eckrich

Notary Public ID No. 1264513

My Commission Expires:

Sep. 16, 2023