COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2014-00371**

In Re the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

REBUTTAL TESTIMONY OF
KENT W. BLAKE
CHIEF FINANCIAL OFFICER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Dated: April 14, 2015

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

A. My name is Kent W. Blake. I am the Chief Financial Officer 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 respond to certain claims presented in the testimony of the Attorney General, Kentucky Industrial Utility Customers, Inc. ("KIUC"), The Kroger Co. ("Kroger"), Wal-Mart Stores East, LP and Sam's East Inc. ("Wal-Mart") and Kentucky School Board Association ("KSBA").

Scrutiny of Company's Application and Forecast Test Year

Q. Do you have any comments on the contention by KIUC's witness that increases in rates over time should give rise to a higher level of review in these cases?

A. Yes. The Commission has carefully evaluated the Companies' applications in the past and will no doubt do so again in the present cases. The fact that the Companies' rates have increased from 2004 through 2013, as noted by Mr. Kollen, reflects the $7.0 billion LG&E and KU have invested in facilities to safely and reliably serve customers during that same time while also complying with existing and newly imposed regulations. These investments have led to the Companies more than doubling their net investment in the business over this same ten year period. These investments have been the subject of numerous proceedings before this Commission and other regulatory authorities wherein the public convenience and necessity or other need for these investments has been demonstrated.

Throughout this period of incremental investment and higher operating costs, the Companies have consistently worked hard to remain cost competitive to reduce the impact on rates. Numerous examples of this are provided in these proceedings. For example, Exhibit KWB-3 in my direct testimony summarizes the most recent electric utility operating cost benchmark study which shows that LG&E and KU are below the industry average cost in all areas of the comparison, and are in the top quartile in the areas of Generation, Transmission and Administrative and General. Exhibit KWB-7 in my direct testimony also demonstrates that KU and LG&E have among the lowest-cost debt in the industry. The extensive discussion of the Companies' budgeting process and production of business records shows the business processes the Companies use to manage their costs and business operations. The Commission has a very clear picture of the Companies' budgeting and planning process.

Q. Do you have any comments on the arguments advanced by the AG, KIUC and Wal-Mart in this case that the Companies' evidence is suspect because it is based on a forward-looking test period?

A. Yes. The Commission has over 20 years of experience with rate cases supported by forward-looking test periods by almost every major utility subject to its jurisdiction, and is fully capable of assessing the reasonableness of the Companies' evidence supporting the request. As attested to by Mr. Staffieri pursuant to 807 KAR 5:001 Section 16 (7) (e) in the Companies' applications in this case, the financial forecasts used in this case are the same financial forecasts prepared for use by management of the Companies and were made in good faith. In fact, those forecasts were prepared with the knowledge that they would not only be used to set objectives and market expectations but also be used to support the

Companies' applications to establish retail base rates in Kentucky. The Companies have submitted extensive evidence showing not only their estimated budgets for the test period, but detailed explanations and documents supporting their business processes for developing the budget estimates. Contrary to the suggestion by KIUC's witness that the projections and estimates presented by the Companies "tend to reflect expenses that may not actually be incurred if they were restrained by the discipline of actual cost management," the detailed explanations of the Companies' bottom-up approach to budgeting demonstrates the reasonableness of the estimates and confirm that the core values of operating efficiently and controlling costs to the extent practicable are embedded in our organization.

Cost of Capital

Q. Do you have any comments on the cost of capital arguments advanced by the intervenors in this case?

A. Yes. While the Companies' rebuttals to the specific contentions on the cost of equity and capital structure are addressed by Dr. Avera and on the cost of debt by Mr. Arbough, I do have two general comments.

First, the witnesses for the AG and Wal-Mart reference surveys of awarded returns on equity and capital to support some selective arguments on the direction of the cost of capital. The calendar year 2014 survey referenced by the AG's witness shows that during 2014, the average authorized cost of capital for electric utilities was 7.67 percent, versus an average cost of capital of 7.69 percent for stand-alone gas distribution companies. In contrast LG&E used a 7.36 percent cost of capital and KU used a 7.38 percent cost of capital to compute the revenue requirement in this proceeding. This comparison demonstrates the reasonableness of the cost of debt, capital structures and proposed return on equity for the Companies in these cases.

Secondly, selective references have been made to surveys of awarded returns on equity most notably that of Regulatory Research Associates. I would simply point out that, with respect to vertically-integrated utilities such as KU and LG&E, authorized returns on equity have averaged approximately 10 percent for both the past three calendar years and the most recent twelve month period ended March 31, 2015.

<u>Green River Units</u>

Q. Do the Companies agree with the recommendation of KIUC witness Kollen and AG witness Radigan to remove the operating expenses associated with KU's Green River Units 3 and 4?

A. No. As discussed in Mr. Thompson's testimony, KU expects to cease operating the Green River Units 3 and 4 in April 2016, but may extend their operation to April 2017 based on grid reliability concerns. For purposes of developing our forecast used in this proceeding, the Companies assumed these units would be retired in April 2016. The costs incurred to operate these units and deliver power for the benefit of our customers during the forecast year are prudently incurred costs which KU has the right to recover. Removal of these costs from the revenue requirement calculation in this case would understate the cost to KU of serving its customers.

If the Commission, nevertheless has concerns about including this cost in the revenue requirement given the projected finite, albeit uncertain, duration of its incurrence, the establishment of a regulatory asset in this case for the complete recovery of Green River Units 3 and 4 costs incurred during the forecast test year through the retirement of those units, as suggested by Mr. Kollen and Mr. Radigan, would be a reasonable alternative. In order to establish a regulatory asset for such costs, the Companies would need explicit approval by the Commission of cost recovery. Moreover, the Companies suggest that a three-year amortization and recovery period, given the amounts and nature of the costs involved, would be reasonable. The amortization level of the regulatory asset should be included in KU's revenue requirement in this case in order to provide a better matching of the cost of the service with the service provided to the customer.

<u>Capital Construction Slippage for the Companies</u>

Q. Do the Companies believe that a "slippage factor" should be applied to their forward-looking test period capital construction as suggested by Messrs. Radigan and Kollen?

A. No. As the Companies have explained in their discovery responses, the calculated capital construction slippage factors (97.803% for KU and 97.728% for LG&E) demonstrate their accuracy in predicting the cost of utility plant additions and the timing of new plant being placed in service. This accuracy has been achieved through use of a very robust process for forecasting capital expenditures and managing to that forecast. Given these high degrees of accuracy, the need to apply a slippage factor does not exist and the Commission should decline to do so.

Q. Are there any potential adverse consequences from imposing a "slippage factor" to projected capital construction in a forward-looking test period rate case?

A. Yes. If a purely numeric slippage factor calculation based on historic results is used to either reduce or increase the projected capital construction costs, it can provide a disincentive for utilities to continue their efforts to reduce capital costs after having established its annual budget. In forward-looking test period rate cases, a utility is required to provide their actual forecast for capital spend "made in good faith". If a utility has historically been successful in managing down capital cost estimates, it would not be allowed to recover its then best estimate of capital spend for its forward-looking test period. In contrast, a utility that has been less effective in managing to or below its costs estimates and have incurred significant overruns on capital projects would actually be rewarded by being provided a revenue requirement above its best estimate of capital construction costs.

Q. Are the Companies aware of instances in which the Commission has not applied a "slippage factor" to projected capital construction in a forward-looking test period rate case?

A Yes. Contrary to Mr. Kollen's testimony, Commission precedent does not require "slippage factor adjustments" to projected capital expenditure in all forward-looking test period rate cases. In fact, with the exception of rate proceedings involving Kentucky-American Water Company ("KAWC"),[1] the Commission has applied a slippage adjustment factor in only one other proceeding.[2] Since that decision, which was entered almost ten years ago, the Commission has not applied a slippage adjustment factor in any non-KAWC forward-looking test period proceeding. The table below lists the forward-looking test period rate cases since 2006 in which the Commission made specific findings regarding rate base or capital expenditures and each applicant's reported slippage factor.[3]

Case Number	Utility	Utility's Calculated Average	Date of Order

[1] The Commission's treatment of KAWC appears based upon historic concerns regarding that utility's budgeting process. *See, e.g.*, Case No. 95-554, *Application of Kentucky-American Water Company to Increase Its Rates* (Ky. PSC Nov. 19, 1993) at 3 ("Based on the historical relationship demonstrated by the slippage factor, the Commission concluded Kentucky-American's "very best estimate(s)" of construction spending was inaccurate and showed a pervasive pattern of over budgeting for construction. To eliminate Kentucky-American's historical overestimation, the Commission reduced the forecasted recurring and specific budget projects by their respective slippage factors."

[2] Case No. 2005-00042, *An Adjustment of the Gas Rates of Union Heat, Light and Power Company* (Ky. PSC Dec. 22, 2005).

[3] Since its decision in Case No. 2005-00042, the PSC has considered 11 non-KAWC forward-looking test period applications. The seven cases that are not listed were resolved through unanimous settlement agreements. Accordingly, the Commission was not required to address rate base or capital expenditures.

		Slippage Factor[4]	
2010-00167	East Kentucky Power Coop.	81.396	01/14/2011
2012-00535	Big Rivers Electric Corp.	102.581	10/29/2013
2013-00148	Atmos Energy Gas	105.442	04/22/2014
2013-00199	Big Rivers Electric Corp.	95.790	04/25/2014

KU's and LG&E's slippage factors, which are 97.803 percent and 97.728 percent, compare very favorably to those listed above.[5] Given this greater accuracy and the Commission's decision not to apply a slippage factor in the listed cases, it is clear that Commission precedent does not support the application of a slippage factor adjustment in the current proceedings.

Bonus Depreciation

Q. Please briefly describe the issue presented in the testimony of the witnesses for KIUC and Kroger concerning bonus depreciation.

A. After the Companies filed their applications on November 26, 2014, Congress passed the Tax Increase Prevention Act of 2014. Because the Companies rate cases were prepared and filed before the law was enacted, the effects of the tax extensions were not reflected in their applications. The law provides for the extension of 50% bonus tax depreciation in 2014 for qualified property and further provides 50% bonus tax depreciation in 2015 for long-production-period property. On January 8, 2015, LG&E and KU filed data responses

4 These factors are based upon a ten-year average except for Big Rivers Electric Corporation, which lacked sufficient information to develop a ten-year average slippage factor and provided a factor based upon the available information.

5 The Companies' slippage factor also compares favorably to that of Union Light, Heat and Power Company ("ULH&P")"in Case No. 2005-00042. In that proceeding, which involved a request for adjustment of gas rates, ULH&P reported a slippage factor of 97.045 percent for its gas operations and 100.6 percent for its electric operations. *See* Case No. 2005-00042, Order of Dec. 22, 1994 at 9.

to AG 1-27 for KU and to AG 1-26 for LG&E providing an analysis of the impact on each company's revenue requirement for the base period and forward-looking test period based on certain scenarios.

Q. Do the Companies agree the impact of the tax extensions provided by the Tax Increase Prevention Act of 2014 should be reflected in the calculation of their revenue requirements?

A. Yes. The Commission's regulation at 807 KAR 5:001, Section 16(6)(d) contemplates such a revision can be made to "reflect statutory or regulatory enactments that could not, with reasonable diligence, have been included in the forecast on the date it was filed."

Q. Do the Companies agree that the revenue requirement impact of reflecting the extension of bonus depreciation should be those scenarios which provide the lowest revenue requirement for the forward-looking test period in this proceeding?

A. No. In responding to AG 1-27 for KU and AG 1-26 for LG&E, the Companies focused solely on the question of the impact on the revenue requirement for the base period and forward-looking test period. However, the decision to elect or "opt out" of bonus depreciation impacts the revenue requirement for customers over the life of the underlying asset additions. Such long-term investment decisions have historically been made by the Companies and this Commission based on the relative Net Present Value Revenue Requirement ("NPVRR") of the alternatives, with the lowest NPVRR being the best economic answer for customers absent any operational, compliance or other considerations. Therefore, the Companies performed a NPVRR analysis for the bonus depreciation scenarios previously presented for each company. That analysis is included as Rebuttal Exhibit KWB-1.

Q. Does this analysis alter the recommendations suggested by the single year revenue requirement impact included in AG 1-26 for LG&E?

A. No. It does not change the prior presumption that LG&E will elect to take the bonus depreciation deduction in both 2014 and 2015 as this provides the greatest revenue requirement benefit (base rate and ECR) from accelerated depreciation over the life of these underlying assets with a NPVRR $110.1 million greater than it would be without this extension ($204.3 million vs. $94.2 million); $46.8 million greater that it would be if LG&E were to elect bonus depreciation in 2014 but opt out in 2015 ($204.3 million vs. $157.5 million); and $117.6 greater than if LG&E were to opt out of bonus depreciation for both 2014 and 2015 ($204.3 million vs. $86.7 million).

Q. Does this analysis alter the presumption suggested by the single year revenue requirement impact included in AG 1-27 for KU?

A. Yes. That one-year analysis suggested that KU would opt out of bonus depreciation in 2015 as the enhanced cash flow benefit of accelerated "bonus" depreciation would be more than offset by the combination of an offsetting loss of its Section 199 deduction and an increase in deferred tax assets. The Section 199 deduction cannot be taken if KU is in a taxable loss position which is projected to be the case if KU elects to take the bonus depreciation deduction in 2015. This taxable loss is reflected as an increase to deferred tax assets. Essentially, KU's capitalization requirements would not be reduced in 2015 because the extra cash tax benefit of bonus depreciation cannot be used in that year. However, the analysis projects that KU would be able to utilize that benefit in 2016, thus removing the deferred tax asset offset. Therefore, the benefit of bonus depreciation taken in 2015 lasts 20 years whereas the offsetting deferred tax asset increase only lasts one year, thus providing a net benefit to customers over the twenty year tax life of the assets. This intuitive conclusion to take the bonus depreciation deduction as offered in both 2014 and 2015 is projected in this analysis to provide a NPVRR benefit that is $60.3 million greater than if KU elected bonus depreciation in 2014 but opted out in 2015 ($258.9 million vs. $198.6 million); $108.5 million greater than if bonus depreciation had not been extended ($258.9 million vs. $150.4 million); and $140.5 million greater than if KU opted out of bonus depreciation for both 2014 and 2015 ($258.9 million vs. $118.4 million).

Q. What is the impact to the revenue requirements in these proceedings if KU and LG&E both elect to take bonus depreciation in 2014 and 2015?

A. As detailed in LG&E's response to AG1-26 and KU's response to AG 1-27, the revenue requirement would decline by $3.4 million for LG&E's electric operations, decline by $1.9 million for LG&E's gas operations and increase by $3.1 million for KU when compared to the "as-filed" position for each utility.

Q. Are there any adjustments that should be made to the calculation supplied by Mr. Kollen to support his position with respect to the impact of the bonus depreciation extension on KU's revenue requirement?

A. Yes. First, Mr. Kollen used the incorrect tab in the Company's bonus depreciation excel workbook provided in response to AG 1-27 to calculate his capitalization adjustment. Mr. Kollen incorrectly used "Tab 3 – Opt out 2015" instead of "Tab 5 – Opt out 2015 with Rev." Tab 5 is the more appropriate tab to use as it reflects the increase in taxable income associated with the potential rate increase. Second, Mr. Kollen's adjustment to operating income for the Sec. 199 deduction in the amount of $0.541 million is reversed and should be removed. There is no associated increase in the Company's tax provision if it opts out of bonus depreciation as the Company would be able to take the Sec. 199 deduction.

Q. Are there any adjustments that should be made to the calculation supplied by Mr. Kollen to support his position with respect to the impact of the bonus depreciation extension on LG&E's revenue requirement?

A. Yes. First, Mr. Kollen incorrectly applied a jurisdictional factor to the reduction in capitalization adjustment associated with the additional accumulated deferred income taxes of $54.238 million. The $54.238 million represents an electric only figure and should not be reduced to $44.806 million as shown on Exhibit LK-45, Section III. Second, Mr. Kollen failed to include an adjustment to increase the Company's cost of equity as a result of the impact of the loss of the Sec. 199 deduction. Mr. Kollen used the Company's as filed grossed up return on equity of 8.91% as shown on Exhibit LK-45 and this should be increased to 9.10%. As discussed in the Company's response to AG 1-26, the loss of the Sec. 199 deduction results in an increase in LG&E's tax provision thereby increasing its Net Operating Income Deficiency and Gross-Revenue Conversion Factor.

Team Incentive Award

Q. Have you reviewed Mr. Kollen's recommendation regarding the Companies' Team Incentive Award ("TIA") Program?

A. Yes. Mr. Kollen recommended removal of $6.474 million of employee compensation expense from KU's revenue requirement and $5.967 million from LG&E's revenue requirement associated with the Companies' TIA Program.

Q. Please describe the Companies' Team Incentive Award ("TIA") Program.

A. The TIA Program is an "at risk" pay program in which a part of an employee's annual cash compensation is put at risk and objectives are established for the employee. If certain performance results are achieved, a cash incentive award will be earned. The actual amount of the award depends upon the achieved results.

The TIA Program, which has been in place since the 1990s, was developed to motivate and direct employees toward the achievement of strategic goals and is part of an overall corporate strategy to attract and retain skilled employees by providing competitive financial awards that are commensurate with the employees' talents, cooperation, and contribution. It is intended to link pay with business performance and personal contributions to results, motivate participants to achieve higher levels of performance, communicate and focus on critical success measures, reinforce desired business behaviors, as well as results, and bolster an employee ownership culture.

Q. Who is eligible to participate in the TIA Program?

A. With the exception of certain executives who are covered by a separate short-term incentive program, all active full-time and regular part-time salaried employees, and LG&E/KU hourly and bargaining unit employees, who have at least one month continuous service, are eligible for a TIA.

Q. How are TIAs determined?

A. All eligible employees have a TIA target award. As shown below, the target award is based on an employee's position and annual salary or earnings. The current target awards are shown below.

Employee Status	Target Award
Non-Exempt and Hourly/Bargaining Unit	6% of Annual Earnings
Exempt Individual Contributors	9% of Base Salary
Managers	14% of Base Salary
Senior Managers	25% of Base Salary

Each year the Companies establish performance objectives to support the Companies' business strategies and the weight to be afforded these objectives. The degree to which these objectives are accomplished will determine the amount of the awards.

The Companies recently announced to their employees the performance objectives for the 2015 calendar year. A copy of this announcement is shown as Rebuttal Exhibit KWB-2. The performance objectives and weightings are:

- Net Income – 45%
- Individual/Team Effectiveness – 40%
- Customer Satisfaction – 15%

The amount that an individual employee earns for each performance objective is calculated by multiplying the employee's target award by the weight given the performance objective and by the percentage of the objective met. An individual employee's total award is the sum of the amount earned for each objective.

Q. What are Individual and Team Effectiveness measures?

A. The Companies establish individual and team effectiveness measures each year to ensure their employees are collectively working to achieve strategic business goals. Individual goals will vary by the individual employee and by department. They support respective department and line of business objectives. Team effectiveness measures are specific to each line of business. The Companies have previously provided a complete listing of the specific targets for team effectiveness measures between 2010 and 2014 and the target achievement rates for the period 2010-2013.[6] A copy of similar targets for 2015 is found at Rebuttal Exhibit KWB-3.

Q. Are there any financial targets that must be met before any incentive pay can be awarded?

A. No. In his testimony, Mr. Kollen states that incentive compensation is tied to PPL's EPS. While it is accurate that a minimum PPL EPS achievement was required to pay any cash incentive compensation for the period from 2012 to 2014, this threshold EPS level is no longer applicable. That provision was removed effective for 2015.

Q. Do you agree with Mr. Kollen's statement that Commission precedent requires removal of a portion of the TIA program costs?

A. No. In his testimony, Mr. Kollen has ignored previous Commission decisions that allowed recovery of TIA program costs. The Commission has reviewed the TIA Program on several occasions. In Case No. 98-474,[7] it allowed recovery of KU's TIA costs, but denied proposed adjustments to cover expansion of the plan to all KU employees as inadequately supported and calculated. While denying the adjustment, the Commission noted that "[w]e are not opposed to compensation plans that link employee pay with performance. However, it must be demonstrated that any employee compensation plan is reasonable in total." In Case No. 2000-080,[8] the Commission permitted recovery of LG&E's TIA costs

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[6] Case No. 2014-00371, KU's Response to the Attorney General's Initial Requests for Information, Item 76 (filed Jan. 23, 2015); Case No. 2014-00372, LG&E's Response to the Attorney General's Initial Requests for Information, Item 75 (filed Jan. 23, 2015).

[7] Case No. 98-474, *The Application of Kentucky Utilities Company for Approval of an Alternative Method of Regulation of Its Rates and Services* (Ky. PSC Jan. 7, 2000) at 80 - 83. The KPSC did not discuss TIA in the companion case that involved an investigation of LG&E's rates. Case No. 98-426, *The Application of Louisville Gas and Electric Company for Approval of an Alternative Method of Regulation of Its Rates and Services* (Ky. PSC Jan. 7, 2000).

[8] Case No. 2000-080, *The Application of Louisville Gas and Electric Company to Adjust Its Rates and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks* (Ky. PSC Sept. 27, 2000) at 50.

after making adjustments to reflect actual expenses, a post-test period wage increase, and the effects of the Companies "One Utility Program." In Cases No. 2003-00433[9] and No. 2003-00434,[10] the Commission allowed recovery of all TIA costs without any adjustments.[11]

Q. Do the Companies have any evidence demonstrating that their employee compensation plan is reasonable in total?

A. Yes. In addition to the various market surveys referenced by the Companies in discovery, an analysis was prepared by David Wathen of Towers Watson and filed with the Companies' rebuttal in this case. That analysis demonstrates the Companies' total compensation plan is reasonable compared to market conditions.

Q. Is the Companies' TIA comparable to the plans reviewed by the Commission cited in Mr. Kollen's testimony?

A. No. In his testimony, Mr. Kollen fails to note some significant differences in the TIA Program and the incentive pay programs in Cases No. 2010-00036 and No. 2013-00148. For example, the incentive pay program whose expense the Commission disallowed in Case No. 2010-00036 made its awards contingent upon the utility meeting threshold targets tied to the utility's Diluted Earnings Per Share ("EPS"). When determining that the program primarily benefited shareholders, the Commission emphasized this unique feature of the utility's program and the consequences of failing to meet the target:

> We remain unconvinced that Kentucky-American's ratepayers receive any benefit from the AIP program to support the recovery of

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[9] Case No. 2003-00433, *An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Louisville Gas and Electric Company* (Ky. PSC June 30, 2004).

[10] Case No. 2003-00434, *An Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company* (Ky. PSC June 30, 2004).

[11] TIA Program costs were also discussed in discovery responses to discovery requests in Case No. 2008-00252 and Case No. 2009-00549 for LG&E and Cases No. 2008-00251 and No. 2009-00548 for KU.

> AIP's costs through rates. While some consideration is given to non-financial criteria, the AIP appears weighted to financial goals that primarily benefit shareholders. **If these goals are not met, the program is unfunded and no Kentucky-American employee receives an incentive award regardless of how well he or she meets the customer satisfaction or service quality goals.** Accordingly, we find that forecasted labor expense should be decreased by an additional $349,529 to eliminate the ICP.[12]

The exact opposite is the case for the Companies' TIA program. Employees are rewarded for meeting customer satisfaction and service quality goals **even if financial targets are not met**.

Similarly, the incentive compensation program reviewed in Case No. 2013-00148 was tied exclusively to an EPS target and gave no consideration to other criteria. Taking issue with the program's one-dimensional nature and rejecting the costs associated with the program, the Commission stated: "Incentive criteria based on a measure of EPS, with no measure of improvement in areas such as safety, service quality, call-center response, or other customer-focused criteria are clearly shareholder-oriented."[13]

In contrast, fifty-five percent of the current TIA program award is based upon customer satisfaction and individual/team performance criteria which focus on areas like safety, reliability, customer service and cost management. KU and LG&E employees receive incentive pay regardless of the Companies' financial performance so long as customer satisfaction and individual/team performance goals are achieved.

[12] Case No. 2010-00036, *Application of Kentucky-American Water Company for Rates Supported By a Fully Forecasted Test Year* (Ky. PSC Dec. 14, 2010) at 32-33 (emphasis added).

[13] Case No. 2013-00148, *Application of Atmos Energy Corporation For An Adjustment of Rates and Tariff Modifications* (Ky. PSC Apr. 22, 2014) at 20.

Q. Do the Companies agree with Mr. Kollen's position that any incentive compensation tied to financial performance should be removed from the Companies' revenue requirement because it benefits shareholders?

A. No. While a utility's shareholders benefit from improved financial performance, so too do utility customers. A utility with a strong financial position is better able to attract capital at lower costs and thus maintain quality service at lower rates. Moreover, financial performance measures such as net income reflect the results of productivity improvements and efficiency measures. At LG&E and KU, the performance measures employed in the TIA program capture the inherent balance and interrelationship between effective operations and financial performance. This is a delicate balance that the Companies' and this Commission have maintained for decades. The Companies must act prudently in providing safe, reliable and cost effective service in order to be allowed to recover their costs and have the opportunity to earn a fair, just and reasonable return on investment. If the Companies do this, they are able to effectively secure the capital necessary to provide that same safe, reliable and cost effective service.

Q. What is the Companies' response to Mr. Kollen's characterization of incentive pay as "a shareholder cost, not a customer cost"?

A. We disagree with that characterization. The work of the Companies' employees cannot be parsed so as to classify a portion as customer-oriented and another portion as shareholder-oriented given the balance noted above. As such, incentive pay is neither a shareholder cost nor a customer cost. It is simply part of the cost of labor to make available safe and reliable electric and natural gas service to the Companies' customers in the most productive and efficient manner possible.

Furthermore, under Kentucky regulation, a utility is entitled to rates that permit the recovery of reasonable expenses incurred to provide service. While the Commission may disallow a utility's expenses, such action may only be taken if the expenses are unreasonable or excessive. While Mr. Kollen advocates for the removal of incentive pay, he has not objected to overall level of Companies' total employee compensation package nor does he contend that the TIA awards are unreasonable or excessive. In his testimony, he does not discuss the reasonableness of the level of the Companies' total compensation. As demonstrated in the rebuttal testimony of Mr. Wathen of Towers Watson and the various market surveys referenced by the Companies in this proceeding, the Companies' level of employee compensation is not excessive nor is their use of incentive pay unreasonable.

Since the total level of the Companies' employment compensation package is reasonable and the inclusion of incentive pay is not unreasonable, the Companies recovery of TIA Program costs through rates should be authorized.

Headcount

Q. Do you agree with the testimony of Mr. Radigan that the Companies should not be allowed to recover the expense for employees they plan to hire by the end of the forecasted test year but have not hired as of December 31, 2014?

A. No. The Companies have put forth and supported their employment forecasts. Mr. Radigan did not specify any legitimate reason for disallowance of planned additions other than what appeared to be a recurring theme of it not being as known and measurable as historic data and an implication that the Companies may not actually hire these individuals. Mr. Thompson will speak to the positions in Operations. However, for the eighteen Information Technology positions and the five Administrative positions projected to be added between December 31, 2014, and the end of either the base period or the forward-looking test period, twelve and three of those positions, respectively, had been filled as of March 31, 2015. Of the six remaining IT positions, one offer has been extended and there is an active posting for four others. Of the two remaining Administrative positions, there is an active posting for one of those. The Companies' still intend to fill the single remaining IT position and the single remaining Administrative position, the latter of which was not projected to be hired until the forward-looking test period. Company headcount additions are detailed in Rebuttal Testimony Exhibit PWT-3 attached to the rebuttal testimony of Mr. Thompson.

Q. Do you agree with Mr. Kollen's position that the Commission should disallow labor costs associated with all employee additions classified as "core skill building/knowledge retention and transfer as such positions are "almost by definition" duplicative?

A. No. I understand that Mr. Kollen is referencing the "Business Need" summary categories used by the Companies in their responses to KIUC 1-10. However, the characterization of positions in that category as "duplicative" is not accurate. Mr. Thompson will address the Operations positions categorized in that manner. Of the eight positions within Information Technology labeled as "core skill building/knowledge retention and transfer", five of those were simply existing positions which just happened to be vacant due to employee turnover as of March 31, 2012, the ending date of the Companies' test year in their previous rate cases. Two others would have been better classified as "Regulatory Compliance" as they represent incremental headcount necessary to comply with transmission standards PRC-005 (Protective Relay and Communication) and CIP Version 5. The final IT position would have been better classified as “Customer Service” as it was an incremental position needed to provide maintenance and support of the mobile VPN system (NetMotion) used in data communication with field workers and the telecom site monitoring system (TMON). With regard to the seven Administrative positions labeled in this manner, three of those are simply existing positions which just happened to be vacant due to employee turnover as of March 31, 2012. While not direct contractor replacements, two rate analyst positions were added, one of which has already been hired, in order to move more analysis work from third party service providers to in-house resources. An HRIS (Human Resource Information System) analyst was added to provide additional analytics to support the Companies’ workforce management. An additional employee was added to work with community stakeholders to better identify areas and means by which the Companies can better serve the community. None of these positions should be characterized as “duplicative” - that is having two employees for the purpose of doing the work of one employee.

Q. Do you have any final observations about the Companies’ hiring needs and practices?

A. Yes. Again, the Companies have prudently managed their hiring practices in the past and will continue to do so in the future. The Towers Watson analysis prepared by David Wathen supports that the Companies have operated at thin levels for years now and will continue to be lean into the future even after the incremental positions indicated on Rebuttal Testimony Exhibit PWT-1 are added. Suggestions that the Companies have been engaged in a “hiring frenzy” are not accurate.

Q. Do the Companies believe that a reduction in labor expense should be applied based on an historical variance between budget-to-actual for labor expense as suggested by Messrs. Kollen and Willhite?

A. No. It is accurate to say that the Companies did not explicitly embed vacancies caused by employee turnover into their headcount forecast. To do so would create a budget with management challenges. For example, if a department with 100 employees had a historical vacancy rate of 2%, a budget adjusted for this vacancy rate in effect allows that department manager only 98 approved positions - notwithstanding all 100 positions in the Companies' headcount forecast have been approved as part of the business plan based on a demonstrated need for 100 employees. To suggest an adjustment based on historic deviations from budget in this one variable overlooks the fact that the work of the 100 budgeted employees still must be accomplished.

Q. Haven't the Companies had an historical variance between actual and budgeted employee headcount?

A. Yes. However, absent a change in the work to be performed, any reduction in employee headcount has been offset by incremental overtime, incremental use of outside contractors or an increase in the backlog of work to be performed. Rebuttal Exhibit KWB-4 is attached to my testimony and contains an analysis of the Companies' five-year history with respect to employee vacancies. While it shows that the Companies have averaged lower employee headcount than budgeted, it also demonstrates those lower costs have largely been offset by overtime costs exceeding budget. In addition, as many of the Companies' positions to be filled represent replacement of current contractors, it would be safe and reasonable to assume that the Companies would simply retain those outside contractors that they had budgeted to replace if the employee position were not filled, thereby replacing an employee cost with an unbudgeted outside contractor cost.

Q. Are you aware of any prior Commission Orders in forward-looking test period rate cases where the Commission has addressed the issues of adjusting a utility's labor forecast for assumed vacancies?

A. Yes. The Commission previously rejected this type of employee vacancy claim in three separate rate cases where the Attorney General proposed a negative adjustment to forecasted labor expense based upon a historical vacancy rate.[14] There, as here, the claims failed to consider the vacancies' effect on other costs such as overtime and contract labor forecasts. The contentions by Mr. Kollen and Mr. Willhite in support of this adjustment are insufficient for the Commission to reject its previous determinations on this issue.

<u>Pension Expense</u>

Q. Was increasing pension expense a factor in the Companies' decision to file this rate case?

A. No. Pension expense was not a significant rate case driver in this case. Although both Mr. Radigan and Mr. Kollen cite to the size of the increase in pension expense when compared to 2014, the pension expense projected for the Companies' forward-looking test period in this proceeding is not significantly different from the pension expense included in the Companies' last base rate case. The Companies' annual pension cost for the forward-looking test period is approximately $48 million ($23million for LG&E and $24.7 million

[14] *See In the Matter of: Application of Kentucky-American Water Company to Increase its Rates,* Case No. 1995-00554, Order at 32 (Sept. 11, 1996); *In the Matter of: Adjustment of the Rates of Kentucky-American Water Company,* Case No. 2004-00103, Order at 45 (Feb. 28, 2005); *In the Matter of: Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year,* Case No. 2010-00036, Order at 25 (Dec. 14, 2010).

for KU) compared to approximately $46 million ($24.5 million for LG&E and $21.4 million for KU) in the Companies' previous rate case. After factoring in jurisdictional factors for KU and the percentage of internal labor capitalized, the Companies' pension expense for the forward-looking test period is approximately $35 million ($18.3 million for LG&E and $16.7 million for KU) compared to approximately $32 million ($19.1 million for LG&E and $12.7 million for KU) in the Companies' previous rate case.

Q. Is pension expense in these cases calculated any differently than the pension expense proposed in previous cases?

A. No. Pension expense ultimately is an accounting estimate made by the Companies based on the advice of independent licensed accuracies and necessarily the best available estimates and assumptions. The pension expense in this case is no different from this perspective than in other cases.

Q. In determining the Companies' Projected Benefit Obligations, the Companies used the RP-2014 Mortality Table. Can you explain why the Companies did so?

A. As discussed more fully in Mr. Arbough's Rebuttal Testimony, the SEC and the public accounting profession, including the Companies' own external auditor, pointed to the RP-2014 Mortality Table ("RP-2014") as the most current information available with respect to mortality rates, encouraging the Companies' to consider these tables and scales unless they had credible information supporting the use of a different table and scale in developing its mortality assumptions. The Companies' had an analysis conducted by Towers Watson, included as Rebuttal Testimony Exhibit DKA-2 to Mr. Arbough's rebuttal testimony, which provided credible evidence supporting the use of specific tables and scales from RP-2014, with adjustments for higher mortality in Kentucky and the Companies' actual experience. Therefore, this represented the mortality assumptions adopted by the Company effective December 31, 2014. While Mr. Radigan points to the uncertainty as to the timing of the adoption of RP-2014 by the Internal Revenue Service, the decision of the IRS has no bearing on the Companies' pension expense to be recorded in accordance with generally accepted accounting principles which is the basis for pension cost recovery in Kentucky.

<u>Inflation Adjustment Factor</u>

Q. Have you reviewed Mr. Townsend's recommendations regarding the Companies' inclusion of inflation in calculating their forward-looking test periods' non-labor O&M expenses?

A. Yes. Mr. Townsend objects to the Companies' use of a 2.0 percent inflation adjustment factor for non-labor costs in those segments of their budgets where better information is unavailable and recommends that KU's revenue requirement be reduced by $2.1 million and LG&E's revenue requirement be reduced by $1.2 million to eliminate the effects of this adjustment. Mr. Townsend asserts that, except in periods of severe inflation, the Companies' recovery for non-labor O&M costs should be limited to "actual costs recorded in the historical period, adjusted for certain known and measurable changes."[15]

Q. Do you agree with Mr. Townsend's recommendations regarding the Companies' use of a general inflation rate in their forecasted test periods?

A. No. The Companies' use of a 2.0 percent general inflation guideline for consideration in developing non-labor expense budgets was simply a guideline and not an inflation rate

[15] Case No. 2014-00371, Prefiled Direct Testimony of Neal Townsend on Behalf of the Kroger Co. at 8 (filed Mar. 6, 2015); Case No. 2014-00372, Prefiled Direct Testimony of Neal Townsend on Behalf of the Kroger Co. at 9 (filed Mar. 6, 2015).

applied to non-labor expenses in the development of the Companies' forward-looking test period in this proceeding. When the Companies prepare their budgets, there are many factors taken into consideration. The following are examples previously referenced by the Companies:

- Known contracts. For example if contracts are already in place for certain segments of the business, the escalation rates that can be derived from those contracts are included.

- Specific scopes of work. For example there is a power plant planned outage schedule for each year in the budget. This is based on the historical and estimated run-times and operating hours of each unit, and the work to be done is a function of where each unit is in its outage cycle, as well as other scopes of work that have been identified to address known or trending issues on that particular generating unit. For the electric and gas distribution areas, the work order backlog at the time that the budget is prepared also factors into their costs. Depending on the extent of the backlog, contractor costs can be increased or decreased. Another example for electric distribution is the emerald ash borer and its impact on the trees in the service territories of each company. The scope of work for Electric Distribution has changed to now include additional costs for clearing dead or dying trees as a result of that insect.

- Variable costs based on levels of production. For example the generation forecast includes generation by unit by month. Each unit has a variable cost of production to cover costs such as limestone and ammonia usage.

- Storm outage restoration costs are based on a 10-year average of historical costs, which is then brought into "current dollars" based on a Consumer Price Index projection.

- Bad debt expense is based on a combination of recent history on the percent of net charge-offs as well as known and anticipated trends in the local economies.

These areas were merely some examples of how non-labor expenses are developed. However, all non-labor expense estimates were thoughtfully developed and thoroughly reviewed at multiple levels. The use of the 2.0 percent guideline for non-labor inflation was more often used for later years of the Companies' five-year business plan, not the financial forecast used to set rates in this proceeding. The Companies' overall methodology for developing their non-labor expense budgets reflect the effective cost management of the Companies whether it be based on negotiated contractual arrangements or other support.

This 2.0 percent guideline is also supported by published projections of inflation such as the Congressional Budget Office ("CBO"). Interestingly, Mr. Townsend himself points to the CBO forecasts of core inflation of 1.8 percent to 2.1 percent in 2015 and 1.9 percent to 2.2 percent in 2016.[16] These forecasts are supportive of the Companies' guideline.

Q. Do the Companies agree with Mr. Townsend's recommendation that inflation adjustments should only be made in times of severe inflation?

A. No. Whether the inflation rate is 1.0 percent or 10 percent, it has an effect on the cost of providing service. To place a restriction on the use of inflation adjustments is a prescription for rates that do not reflect the actual cost of service. The appropriate course of action is not to arbitrarily place restrictions on the use of inflation assumptions, but to review the reasonableness of and support for those assumptions.

Mr. Townsend's proposed restrictions on the use of inflation assumptions are also contrary to Kentucky regulation. Mr. Townsend argues that non-labor O&M costs should be limited to "actual costs recorded in the historical period, adjusted for certain known and measurable changes." In effect, he argues that only historical test period ratemaking methodology should be used to establish non-labor O&M costs. Kentucky regulation, however, clearly permits the use of a forward-looking test period and the use of forecast

[16] Case No. 2014-00371, Prefiled Direct Testimony of Neal Townsend on Behalf of the Kroger Co. at 9; Case No. 2014-00372, Prefiled Direct Testimony of Neal Townsend on Behalf of the Kroger Co. at 10.

adjustments. The use of reasonable inflation assumptions in developing non-labor O&M costs, therefore, is not only reasonable but completely permissible.

<u>Normalization of Uncollectible Expense and Late Payment Revenues</u>

Q. Why would it be inappropriate to utilize a five year average for 2010 through 2014 for uncollectible expenses as Mr. Kollen suggests?

A. The Companies do not believe an adjustment for uncollectible expense is warranted in the case given the most recent history supporting a higher charge off percentage. As discussed in the Companies' response to AG 2-3, the forecasted uncollectible expense to total revenues charge off percentage of 0.40% for KU and 0.28% for LG&E is below the most recent calendar year and reasonable when compared to the five year average charge off percentage. That five-year average charge-off percentage for 2010-2014 is 0.39% for KU and 0.30% for LG&E. Mr. Kollen's suggested approach to utilize the five year average of actual uncollectible expenses is inappropriate as it fails to reflect the very increases in rates over time that he discusses in his own testimony which includes increases attributable to demand side management, fuel and environmental cost recovery mechanisms. Were a five year average deemed warranted in this case to address the variance between the 5-year average net charge-off percentages and the percentages used in this proceeding, it would only represent a revenue requirement reduction of approximately $232,000 for KU and a revenue requirement increase of approximately $241,000 for LG&E.

Q. Why would it be inappropriate to utilize a five year average for 2010 through 2014 for late payment fees as Mr. Kollen suggests?

A. Mr. Kollen's suggestion to utilize the five year average for late payment fee revenues (2010 – 2014) would inappropriately overstate the expected level of late payment fees in the forward-looking test period. As discussed in the Company's response to AG 2-4, late payment fees were lower in 2013 and 2014 because the Company reduced the late payment fee from 5% to 3% for certain rate schedules, including residential service, per the settlement reached in Case No. 2012-00221 (KU) and Case No. 2012-00222 (LG&E). The forecasted test year late payment fees proposed by the Company appropriately reflect the lower late payment fee of 3% and experience since that change.

Q. In response to Commission data requests, Mr. Kollen notes that he did not consider reasons for variations in either uncollectible expenses or late payment fees and explained why he did not need to do so. Do you agree with his position?

A. No. The financial forecast used in a forward-looking test period rate case should include managements' best estimates with respect to revenues and expenses developed in good faith. It would, therefore, be unreasonable to ignore a tariff rate change in the development of late payment fee projections or to ignore the level of forecasted revenues when estimating uncollectible expenses. Mr. Kollen went on to suggest multiple times in his response that the Companies took the same approach in developing their estimate of maintenance expense for the Mitchell plant. However, the Companies do not own or operate the Mitchell plant and have included no maintenance expenses related to such activity in this proceeding.

Capitalization of Property Tax Expense on Construction Work in Progress for the Companies

Q. Do the Companies agree with Mr. Kollen's calculation of an adjustment to capitalize property taxes on CWIP and the amount of the corresponding adjustment to the Companies' revenue requirement in this proceeding?

A. No. The adjustments proposed by Mr. Kollen overstate the amount of property taxes that could be capitalized. First, Mr. Kollen's calculation assumes that property taxes should be capitalized on 100% of CWIP which is not appropriate given the annual assessment of property taxes in Kentucky is based on values as of December 31st. Second, Mr. Kollen's calculation overstates the rate at which CWIP is taxed as the majority of CWIP as of December 31st, 2014 and 2015, is comprised of property designated as manufacturing machinery with a property tax rate of 15 cents per $100. Lastly, Mr. Kollen's proposal fails to include a capitalization adjustment to the revenue requirement for the property tax amounts to be capitalized.

Q. Do the Companies agree with Mr. Kollen's recommendation to capitalize property taxes on <u>ALL</u> Construction Work in Progress (CWIP)?

A. No. Per PWC's Guide to Accounting for Utilities and Power Companies, property taxes should generally be expensed as they represent a cost of owning the property and are not a direct incremental cost of construction. However, the Companies believe that the FERC Uniform System of Accounts does allow for some capitalization of property taxes. For projects with construction periods of less than one year, there would be little to no impact in light of the December 31 point in time basis for property valuation. Likewise, the capitalization and corresponding tracking of property taxes on small dollar projects would have a negligible impact on expense and could be offset by the associated increase in administrative costs. Moreover, capitalization of property taxes could ultimately lead to increased cost of service for customers due to the cost of capital associated with the amounts capitalized. It is for these reasons that the Companies have historically followed their current accounting policy with respect to limiting their capitalizing property taxes on CWIP.

Q. If deemed appropriate by this Commission, would the Companies consider expanding its accounting policy with respect to capitalizing property taxes on CWIP?

A. Yes. The Companies would be willing to consider a change in accounting policy to capitalize property taxes on projects costing more than $100,000 with a construction period of greater than 12 months in duration. Please see Rebuttal Exhibit KWB-5 for support of the corresponding reduction in the revenue requirement in this proceeding of $510,000 for KU and $537,000 for LG&E if this change in accounting policy were adopted.

<u>Extension of Amortization Periods for the Companies</u>

Q. Should KU make an adjustment to operating income for the forward-looking test period for the Mountain Storm Regulatory Asset or the MISO Exit Fee Regulatory Asset as proposed by Mr. Kollen in Exhibit LK-34?

A. No. The Mountain Storm Regulatory Asset is only associated with KU's Old Dominion Power customers served under Virginia jurisdiction and has no impact on Kentucky retail customers. The MISO Exit Fee Regulatory Asset is only associated with KU's wholesale jurisdictional customers and will have no impact on the Kentucky retail customers.

Q. Should LG&E make an adjustment to operating income for the forward-looking test period to extend the amortization period for the 2011 Summer Storm Regulatory Asset as proposed by Mr. Kollen in Exhibit LK-35?

A. No. A five year amortization period for the $8,052,125 2011 Summer Storm Regulatory Asset was agreed to in the settlement of Case No. 2012-00222. Extending the amortization period beyond 2017 as suggested by Mr. Kollen conflicts with the settlement reached in and approved by the Commission in Case No. 2012-00222.

<u>Other Adjustments to Intervenor Calculations</u>

Q. To the extent the Commission were to rely on any adjustments provided by AG witness Radigan and KIUC witness Kollen, are there any other general adjustments that should be made to those calculations?

A. Yes. AG witness Radigan's recommended operating income adjustments for KU are based on "total company." Mr. Radigan did not apply the applicable jurisdictional percentages to the adjustments, thereby overstating their impact.

KIUC witness Mr. Kollen's recommended operating income adjustments for LG&E are split using an electric rate base ratio of 82.61%. The correct electric/gas ratio is 79/21 for these types of adjustments.

<u>Recommendation</u>

Q. What is your recommendation to the Commission?

A. LG&E's requested revenue requirement for electric operations is $28 million and $14.3 for gas operations.[17] KU's requested revenue requirement for its Kentucky retail operations is $155.3 million.[18] As previously discussed, the Companies recommend the Commission adjust these revenue requirements to reflect the impact of the bonus depreciation tax credits shown in the Companies' response to AG 1-26 for LG&E and AG 1-27 for KU The resulting revenue requirement for LG&E and KU is shown in Rebuttal Exhibit KWB-6. For the reasons stated in their respective applications and in these records, the Companies request the Commission approve changes in base rates to recover the revenue deficiencies shown in Rebuttal Exhibit KWB-6 for service rendered on and after July 1, 2015.

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[17] Case No. 2014-00372,Supplemental Response of LG&E to Commission Staff's First Request for Information Question No. 59 (Feb. 27, 2015).

[18] Case No. 2014-00371,Supplemental Response of KU to Commission Staff's First Request for Information Question No. 59 (Feb. 27, 2015).

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Kent W. Blake**, being duly sworn, deposes and says that he is Chief Financial Officer 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.

Kent W Blake
Kent W. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of April 2015.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2018

Exhibit List to Rebuttal Testimony of Kent W Blake

1. Rebuttal Exhibit KWB-1 NPVRR analyses for the bonus depreciation scenarios for each company.

2. Rebuttal Exhibit KWB-2 2015 Team Incentive Award Announcement

3. Rebuttal Exhibit KWB-3 TIA Team Targets

4. Rebuttal Exhibit KWB-4 Analysis of the Companies' five-year employee vacancies history

5. Rebuttal Exhibit KWB-5 capitalize property taxes on projects costing more than $100,000 with a construction period of greater than 12 months in duration.

6. Rebuttal Exhibit KWB-6 Corrected Revenue Requirements, adjusted for impact of bonus tax depreciation

LG&E (In $000)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Total Company																								
Bonus deducted in 2014																								
Bonus		(312,361)																						(312,361)
NOL	(70,162)	70,162																						-
MARSC 20 for 2015 assets			(6,665)	(12,830)	(11,867)	(10,978)	(10,154)	(9,393)	(8,687)	(8,037)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(3,965)	(177,727)
Straight Line 7 yrs for 2015 assets			(7,012)	(14,025)	(14,025)	(14,025)	(14,025)	(14,025)	(14,025)	(7,012)														(98,173)
Book Depreciation		15,618	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	13,795		588,261
Cash Tax Benefit Timing Differences	(24,557)	(79,303)	5,508	895	1,233	1,544	1,832	2,098	2,345	5,027	7,519	7,520	7,519	7,520	7,519	7,520	7,519	7,520	7,519	7,520	7,519	2,053	(1,388)	0
Section 199 Deduction	3,403	-	(10,228)	(7,139)	(8,783)	(10,344)	(10,620)	(10,673)	(10,722)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)		(204,591)
Cash Tax Benefit for Section 199	1,191	-	(3,580)	(2,499)	(3,074)	(3,620)	(3,717)	(3,735)	(3,753)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)		(71,607)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base	(24,557)	(79,303)	5,508	895	1,233	1,544	1,832	2,098	2,345	5,027	7,519	7,520	7,519	7,520	7,519	7,520	7,519	7,520	7,519	7,520	7,519	2,053	(1,388)	0
Cost of Capital	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact	(1,812)	(5,853)	406	66	91	114	135	155	173	371	555	555	555	555	555	555	555	555	555	555	555	152		0
Pro forma NOI impact	1,191	-	(3,580)	(2,499)	(3,074)	(3,620)	(3,717)	(3,735)	(3,753)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)		(71,607)
Gross Up Factor	0.61334	0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req	(1,013)	(9,542)	(4,935)	(3,783)	(4,639)	(5,453)	(5,570)	(5,568)	(5,566)	(5,263)	(4,977)	(4,977)	(4,977)	(4,977)	(4,977)	(4,977)	(4,977)	(4,977)	(4,977)	(4,977)	(4,977)	(5,604)		(111,681)
Cumulative impact on Rev Req		(9,542)	(17,432)	(15,648)	(16,401)	(17,074)	(17,013)	(16,801)	(16,559)	(15,986)	(15,123)	(14,260)	(13,397)	(12,534)	(11,672)	(10,808)	(9,946)	(9,083)	(8,220)	(7,357)	(6,494)	(6,258)		
Net Present Value		(157,463)																						
Bonus deducted in 2014 and 2015																								
Bonus		(312,361)	(275,900)																					(588,261)
NOL	(124,835)	70,162	54,673																					-
Book Depreciation		15,618	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	13,795	22,354	610,615
Cash Tax Benefit Timing Differences	(43,692)	(79,303)	(67,135)	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	4,828	7,824	0
Section 199 Deduction	6,054	-	(0)	(8,105)	(9,609)	(11,109)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)		(203,996)
Cash Tax Benefit for Section 199	2,119	-	(0)	(2,837)	(3,363)	(3,888)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)		(71,399)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base	(43,692)	(79,303)	(67,135)	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	10,295	4,828	7,824	7,824
Cost of Capital	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact	(3,224)	(5,853)	(4,955)	760	760	760	760	760	760	760	760	760	760	760	760	760	760	760	760	760	760	356		577
Pro forma NOI impact	2,119	-	(0)	(2,837)	(3,363)	(3,888)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)		(71,399)
Gross Up Factor	0.61334	0.61334	0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req	(1,802)	(9,542)	(8,078)	(3,230)	(4,049)	(4,865)	(4,983)	(4,983)	(4,983)	(4,983)	(4,983)	(4,983)	(4,983)	(4,983)	(4,983)	(4,983)	(4,983)	(4,983)	(4,983)	(4,983)	(4,983)	(5,611)		(111,927)
Loss of Sect 199 on gross up factor for NOI filed																								
NOI Deficiency as filed			19,000																					
Difference in gross up factor (1.64241-1.60858)			0.03383																					
Revenue Impact			643																					
Estimated Rev Req impact from loss of Sect 199 on gross up factor (ECR)		5,000	5,000																					
Cumulative impact on Rev Req		(4,542)	(17,235)	(26,107)	(25,745)	(25,379)	(24,316)	(23,135)	(21,954)	(20,772)	(19,591)	(18,409)	(17,228)	(16,046)	(14,865)	(13,684)	(12,502)	(11,321)	(10,139)	(8,958)	(7,776)	(7,222)		
Net Present Value		(204,302)																						
No Bonus deducted in 2014 and 2015																								
MARSC 20 in place of bonus		(8,174)	(22,400)	(27,384)	(25,331)	(23,431)	(21,673)	(20,047)	(18,544)	(17,763)	(17,654)	(17,654)	(17,654)	(17,654)	(17,654)	(17,654)	(17,654)	(17,654)	(17,654)	(17,654)	(17,654)	(12,791)	(3,965)	(395,695)
Straight Line 7 yrs in place of bonus		(6,742)	(20,497)	(27,509)	(27,509)	(27,509)	(27,509)	(27,509)	(20,767)	(7,012)														(192,566)
Book Depreciation		15,618	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	13,795	22,354	610,615
Cash Tax Benefit Timing Differences		246	(4,719)	(8,918)	(8,199)	(7,534)	(6,919)	(6,350)	(3,464)	1,623	4,116	4,116	4,116	4,116	4,116	4,116	4,116	4,116	4,116	4,116	4,116	351	6,436	7,824
Section 199		(11,023)	(8,649)	(5,443)	(7,047)	(8,638)	(8,941)	(9,020)	(9,420)	(10,125)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,706)		(204,188)
Cash Tax Benefit for Section 199	-	(3,858)	(3,027)	(1,905)	(2,466)	(3,023)	(3,129)	(3,157)	(3,297)	(3,544)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,747)		(71,466)
Reduce Capitalization/Rate Base	-	246	(4,719)	(8,918)	(8,199)	(7,534)	(6,919)	(6,350)	(3,464)	1,623	4,116	4,116	4,116	4,116	4,116	4,116	4,116	4,116	4,116	4,116	4,116	351		7,824
Cost of Capital	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact	-	18	(348)	(658)	(605)	(556)	(511)	(469)	(256)	120	304	304	304	304	304	304	304	304	304	304	304	26		577
Pro forma NOI impact	-	(3,858)	(3,027)	(1,905)	(2,466)	(3,023)	(3,129)	(3,157)	(3,297)	(3,544)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,747)		(71,466)
Gross Up Factor	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		0.64306
Bonus impact on Rev Req	-	(5,971)	(5,249)	(3,986)	(4,776)	(5,566)	(5,661)	(5,638)	(5,525)	(5,325)	(5,226)	(5,226)	(5,226)	(5,226)	(5,226)	(5,226)	(5,226)	(5,226)	(5,226)	(5,226)	(5,226)	(5,787)		(110,974)
Cumulative impact on Rev Req		(5,971)	(5,221)	(4,499)	(6,313)	(8,044)	(9,003)	(9,775)	(10,390)	(10,588)	(10,303)	(9,831)	(9,358)	(8,886)	(8,414)	(7,941)	(7,469)	(6,997)	(6,525)	(6,052)	(5,580)	(5,668)		
Net Present Value		(86,680)																						
Bonus deducted in 2014 (As Filed Pre Law Change)																								
Bonus		(87,887)																						(87,887)
NOL																								-
MARSC 20 for 2014 assets		(8,418)	(16,205)	(14,988)	(13,866)	(12,824)	(11,863)	(10,972)	(10,151)	(10,016)	(10,016)	(10,016)	(10,016)	(10,016)	(10,016)	(10,016)	(10,014)	(10,016)	(10,014)	(10,016)	(10,014)	(5,008)		(224,481)
MARSC 20 for 2015 assets			(6,665)	(12,830)	(11,867)	(10,978)	(10,154)	(9,393)	(8,687)	(8,037)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(3,965)	(177,727)
Straight Line 7 yrs for 2015 assets			(7,012)	(14,025)	(14,025)	(14,025)	(14,025)	(14,025)	(14,025)	(7,012)	-	-	-	-	-	-	-	-	-	-	-	-	-	(98,173)
Book Depreciation		15,618	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	13,795	22,354	610,615
Cash Tax Benefit Timing Differences		(28,240)	(164)	(4,350)	(3,620)	(2,945)	(2,320)	(1,742)	(1,207)	1,522	4,013	4,014	4,013	4,014	4,013	4,014	4,014	4,014	4,014	4,014	4,014	301	6,436	(205,894)
Section 199 Deduction		(5,543)	(9,280)	(6,075)	(7,681)	(9,274)	(9,579)	(9,659)	(9,733)	(10,111)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,699)		(202,655)
Cash Tax Benefit for Section 199		(1,940)	(3,248)	(2,126)	(2,688)	(3,246)	(3,353)	(3,381)	(3,407)	(3,539)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,745)		(70,929)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base		(28,240)	(164)	(4,350)	(3,620)	(2,945)	(2,320)	(1,742)	(1,207)	1,522	4,013	4,014	4,013	4,014	4,013	4,014	4,014	4,014	4,014	4,014	4,014	301	6,436	7,822
Cost of Capital		0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact		(2,084)	(12)	(321)	(267)	(217)	(171)	(129)	(89)	112	296	296	296	296	296	296	296	296	296	296	296	22		102
Pro forma NOI impact		(1,940)	(3,248)	(2,126)	(2,688)	(3,246)	(3,353)	(3,381)	(3,407)	(3,539)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,745)		(70,929)
Gross Up Factor		0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req		(3,398)	(5,070)	(3,806)	(4,596)	(5,386)	(5,480)	(5,457)	(5,436)	(5,329)	(5,230)	(5,230)	(5,230)	(5,230)	(5,230)	(5,230)	(5,230)	(5,230)	(5,230)	(5,230)	(5,230)	(5,789)		(107,280)
Cumulative impact on Rev Req		(3,398)	(8,468)	(7,223)	(8,512)	(9,717)	(10,149)	(10,393)	(10,572)	(10,603)	(10,330)	(9,870)	(9,409)	(8,948)	(8,488)	(8,027)	(7,566)	(7,106)	(6,645)	(6,184)	(5,724)	(5,821)		
Net Present Value		(94,211)																						
Discount Rate		7.38%																						

Assume for this analysis that book depreciation will be 20 yr straight line property.

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(In $000)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
ECR																								
Bonus deducted in 2014																								
Bonus		(157,322)																						(157,322)
MARSC 20 in place of bonus (40%)			(2,454)	(4,725)	(4,370)	(4,043)	(3,739)	(3,459)	(3,199)	(2,960)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(1,460)	(65,452)
Straight Line 7 yrs in place of bonus (60%)			(7,012)	(14,025)	(14,025)	(14,025)	(14,025)	(14,025)	(14,025)	(7,012)														(98,173)
Book Depreciation		7,866	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	8,181		320,943
Cash Tax Benefit Timing Differences		(52,310)	2,303	(946)	(822)	(707)	(601)	(503)	(412)	2,126	4,594	4,594	4,594	4,594	4,594	4,594	4,594	4,594	4,594	4,594	4,594	1,841	(511)	(1)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base		(52,310)	2,303	(946)	(822)	(707)	(601)	(503)	(412)	2,126	4,594	4,594	4,594	4,594	4,594	4,594	4,594	4,594	4,594	4,594	4,594	1,841	(511)	(1)
Cost of Capital		0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738
NOI Found reasonable impact		(3,860)	170	(70)	(61)	(52)	(44)	(37)	(30)	157	339	339	339	339	339	339	339	339	339	339	339	136	(38)	(0)
Gross Up Factor		0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	
Bonus impact on Rev Req		(6,294)	264	(109)	(94)	(81)	(69)	(58)	(47)	244	527	527	527	527	527	527	527	527	527	527	527	211	(59)	(232)
Cumulative impact on Rev Req		(6,294)	(6,030)	(6,138)	(6,233)	(6,314)	(6,383)	(6,440)	(6,488)	(6,244)	(5,716)	(5,189)	(4,662)	(4,135)	(3,607)	(3,080)	(2,553)	(2,026)	(1,498)	(971)	(444)	(232)	(291)	
Net Present Value		(57,587)																						
Bonus deducted in 2014 and 2015																								
Bonus		(157,322)	(163,621)																					(320,943)
Book Depreciation		7,866	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	8,181	12,196	333,139
Cash Tax Benefit Timing Differences		(52,310)	(51,651)	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	2,863	4,269	0
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base		(52,310)	(51,651)	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	5,617	2,863		0
Cost of Capital		0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact		(3,860)	(3,812)	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	414	211		0
Gross Up Factor		0.61334	0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req		(6,294)	(6,215)	645	645	645	645	645	645	645	645	645	645	645	645	645	645	645	645	645	645	329		(578)
Estimated Rev Req impact from loss of Sect 199 on gross up factor (ECR)		5,000	5,000																					
Cumulative impact on Rev Req		(1,294)	(7,509)	(11,864)	(11,220)	(10,575)	(9,931)	(9,286)	(8,642)	(7,997)	(7,352)	(6,708)	(6,063)	(5,419)	(4,774)	(4,130)	(3,485)	(2,840)	(2,196)	(1,551)	(907)	(578)		
Net Present Value		(77,603)																						
No Bonus deducted in 2014 and 2015																								
MARSC 20 in place of bonus (40%)		(2,360)	(6,997)	(8,926)	(8,257)	(7,638)	(7,065)	(6,535)	(6,045)	(5,767)	(5,728)	(5,728)	(5,728)	(5,728)	(5,728)	(5,728)	(5,728)	(5,728)	(5,728)	(5,728)	(5,728)	(4,324)	(1,460)	(128,377)
Straight Line 7 yrs in place of bonus (60%)		(6,742)	(20,497)	(27,509)	(27,509)	(27,509)	(27,509)	(27,509)	(20,767)	(7,012)														(192,566)
Book Depreciation		7,866	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	8,181	12,196	333,139
Cash Tax Benefit Timing Differences		(433)	(4,006)	(7,136)	(6,902)	(6,685)	(6,484)	(6,299)	(3,768)	1,144	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612	1,350	3,757	4,269
Reduce Capitalization/Rate Base		(433)	(4,006)	(7,136)	(6,902)	(6,685)	(6,484)	(6,299)	(3,768)	1,144	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612	1,350	3,757	4,269
Cost of Capital		0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738
NOI Found reasonable impact		(32)	(296)	(527)	(509)	(493)	(479)	(465)	(278)	84	267	267	267	267	267	267	267	267	267	267	267	100	277	315
Gross Up Factor		0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306
Bonus impact on Rev Req		(50)	(460)	(819)	(792)	(767)	(744)	(723)	(432)	131	415	415	415	415	415	415	415	415	415	415	415	155	431	59
Cumulative impact on Rev Req		(50)	(509)	(1,328)	(2,120)	(2,888)	(3,632)	(4,355)	(4,787)	(4,656)	(4,241)	(3,827)	(3,412)	(2,998)	(2,583)	(2,169)	(1,754)	(1,340)	(925)	(511)	(96)	59	490	
Net Present Value		(26,719)																						
Bonus deducted in 2014 (As Filed Pre Law Change)																								
Bonus		(87,887)																						(87,887)
MARSC 20 for 2014 assets		(2,604)	(5,013)	(4,636)	(4,289)	(3,967)	(3,670)	(3,394)	(3,140)	(3,098)	(3,098)	(3,098)	(3,098)	(3,098)	(3,098)	(3,098)	(3,097)	(3,098)	(3,097)	(3,098)	(3,097)	(1,549)		(69,437)
MARSC 20 for 2015 assets			(2,454)	(4,725)	(4,370)	(4,043)	(3,739)	(3,459)	(3,199)	(2,960)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(2,920)	(1,460)	(65,452)
Straight Line 7 yrs for 2015 assets			(7,012)	(14,025)	(14,025)	(14,025)	(14,025)	(14,025)	(14,025)	(7,012)	-	-	-	-	-	-	-	-	-	-	-	-		(98,173)
Book Depreciation		7,866	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	16,047	8,181	12,196	333,139
Cash Tax Benefit Timing Differences		(28,919)	549	(2,568)	(2,323)	(2,095)	(1,885)	(1,691)	(1,511)	1,042	3,510	3,510	3,510	3,510	3,510	3,510	3,510	3,510	3,510	3,510	3,510	1,299	3,757	4,266
Reduce Capitalization/Rate Base		(28,919)	549	(2,568)	(2,323)	(2,095)	(1,885)	(1,691)	(1,511)	1,042	3,510	3,510	3,510	3,510	3,510	3,510	3,510	3,510	3,510	3,510	3,510	1,299	3,757	4,266
Cost of Capital		0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738
NOI Found reasonable impact		(2,134)	41	(190)	(171)	(155)	(139)	(125)	(111)	77	259	259	259	259	259	259	259	259	259	259	259	96	277	315
Gross Up Factor		0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	
Bonus impact on Rev Req		(3,480)	63	(295)	(267)	(240)	(216)	(194)	(173)	120	403	403	403	403	403	403	403	403	403	403	403	149	431	(102)
Cumulative impact on Rev Req		(3,480)	(3,417)	(3,711)	(3,978)	(4,218)	(4,435)	(4,629)	(4,802)	(4,683)	(4,280)	(3,877)	(3,474)	(3,071)	(2,669)	(2,266)	(1,863)	(1,460)	(1,057)	(654)	(252)	(102)	329	
Net Present Value		(38,597)																						
Discount Rate		7.38%																						

Assume for this analysis that book depreciation will be
20 yr straight line property.

LG&E
(In $000)
Base

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Bonus deducted in 2014																								
Bonus		(155,039)																						(155,039)
NOL	(70,162)	70,162																						-
MARSC 20 for 2015 assets			(4,210)	(8,105)	(7,497)	(6,935)	(6,414)	(5,934)	(5,488)	(5,077)	(5,010)	(5,008)	(5,010)	(5,008)	(5,010)	(5,008)	(5,010)	(5,008)	(5,010)	(5,008)	(5,010)	(5,008)	(2,505)	(112,275)
Straight Line 7 yrs for 2015 assets			-	-	-	-	-	-	-	-														-
Book Depreciation		7,752	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	5,614		267,318
Cash Tax Benefit Timing Differences	(24,557)	(26,994)	3,204	1,841	2,054	2,251	2,433	2,601	2,757	2,901	2,925	2,925	2,925	2,925	2,925	2,925	2,925	2,925	2,925	2,925	2,925	212	(877)	2
Section 199 Deduction	3,403	-	(10,228)	(7,139)	(8,783)	(10,344)	(10,620)	(10,673)	(10,722)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)		(204,591)
Cash Tax Benefit for Section 199	1,191	-	(3,580)	(2,499)	(3,074)	(3,620)	(3,717)	(3,735)	(3,753)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)		(71,607)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base	(24,557)	(26,994)	3,204	1,841	2,054	2,251	2,433	2,601	2,757	2,901	2,925	2,925	2,925	2,925	2,925	2,925	2,925	2,925	2,925	2,925	2,925	212	(877)	2
Cost of Capital	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact	(1,812)	(1,992)	236	136	152	166	180	192	203	214	216	216	216	216	216	216	216	216	216	216	216	16		0
Pro forma NOI impact	1,191	-	(3,580)	(2,499)	(3,074)	(3,620)	(3,717)	(3,735)	(3,753)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)	(3,755)		(71,607)
Gross Up Factor	0.61334	0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req	(1,013)	(3,248)	(5,199)	(3,674)	(4,544)	(5,372)	(5,501)	(5,510)	(5,519)	(5,507)	(5,504)	(5,504)	(5,504)	(5,504)	(5,504)	(5,504)	(5,504)	(5,504)	(5,504)	(5,504)	(5,504)	(5,816)		(111,449)
Cumulative impact on Rev Req		(3,248)	(11,402)	(9,509)	(10,168)	(10,760)	(10,630)	(10,361)	(10,071)	(9,742)	(9,407)	(9,071)	(8,736)	(8,400)	(8,064)	(7,728)	(7,393)	(7,057)	(6,722)	(6,386)	(6,050)	(6,026)		
Net Present Value		(99,876)																						
Bonus deducted in 2014 and 2015																								
Bonus		(155,039)	(112,279)																					(267,318)
NOL	(124,835)	70,162	54,673		-																			-
Book Depreciation		7,752	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	5,614	10,158	277,476
Cash Tax Benefit Timing Differences	(43,692)	(26,994)	(15,484)	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	1,965	3,555	0
Section 199 Deduction	6,054	-	(0)	(8,105)	(9,609)	(11,109)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)		(203,996)
Cash Tax Benefit for Section 199	2,119	-	(0)	(2,837)	(3,363)	(3,888)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)		(71,399)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base	(43,692)	(26,994)	(15,484)	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	4,678	1,965		0
Cost of Capital	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact	(3,224)	(1,992)	(1,143)	345	345	345	345	345	345	345	345	345	345	345	345	345	345	345	345	345	345	145		0
Pro forma NOI impact	2,119	-	(0)	(2,837)	(3,363)	(3,888)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)	(3,964)		(71,399)
Gross Up Factor	0.61334	0.61334	0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req	(1,802)	(3,248)	(1,863)	(3,874)	(4,693)	(5,509)	(5,628)	(5,628)	(5,628)	(5,628)	(5,628)	(5,628)	(5,628)	(5,628)	(5,628)	(5,628)	(5,628)	(5,628)	(5,628)	(5,628)	(5,628)	(5,939)		(111,349)
Loss of Sect 199 on gross up factor for NOI filed																								
NOI Deficiency as filed			19,000																					
Difference in gross up factor (1.64241-1.60858)			0.03383																					
Revenue Impact			643																					
Cumulative impact on Rev Req		(3,248)	(9,726)	(14,243)	(14,525)	(14,804)	(14,386)	(13,849)	(13,312)	(12,775)	(12,238)	(11,701)	(11,164)	(10,628)	(10,091)	(9,554)	(9,017)	(8,480)	(7,943)	(7,406)	(6,870)	(6,644)		
Net Present Value		(126,699)																						
No Bonus deducted in 2014 and 2015																								
MARSC 20 in place of bonus		(5,814)	(15,403)	(18,457)	(17,074)	(15,793)	(14,608)	(13,512)	(12,499)	(11,995)	(11,926)	(11,927)	(11,926)	(11,927)	(11,926)	(11,927)	(11,926)	(11,927)	(11,926)	(11,927)	(11,926)	(8,468)	(2,505)	(267,318)
Straight Line 7 yrs in place of bonus		-	-	-	-	-	-	-	-	-														-
Book Depreciation		7,752	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	5,614	10,158	277,476
Cash Tax Benefit Timing Differences		678	(713)	(1,782)	(1,298)	(849)	(435)	(51)	303	480	504	504	504	504	504	504	504	504	504	504	504	(999)	2,679	3,555
Section 199	-	(11,023)	(8,649)	(5,443)	(7,047)	(8,638)	(8,941)	(9,020)	(9,420)	(10,125)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,706)		(204,188)
Cash Tax Benefit for Section 199		(3,858)	(3,027)	(1,905)	(2,466)	(3,023)	(3,129)	(3,157)	(3,297)	(3,544)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,747)		(71,466)
Reduce Capitalization/Rate Base	-	678	(713)	(1,782)	(1,298)	(849)	(435)	(51)	303	480	504	504	504	504	504	504	504	504	504	504	504	(999)		3,555
Cost of Capital	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact	-	50	(53)	(132)	(96)	(63)	(32)	(4)	22	35	37	37	37	37	37	37	37	37	37	37	37	(74)		262
Pro forma NOI impact	-	(3,858)	(3,027)	(1,905)	(2,466)	(3,023)	(3,129)	(3,157)	(3,297)	(3,544)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,665)	(3,747)		(71,466)
Gross Up Factor	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		0.64306
Bonus impact on Rev Req	-	(5,922)	(4,789)	(3,167)	(3,984)	(4,799)	(4,916)	(4,915)	(5,092)	(5,456)	(5,641)	(5,641)	(5,641)	(5,641)	(5,641)	(5,641)	(5,641)	(5,641)	(5,641)	(5,641)	(5,641)	(5,942)		(111,033)
Cumulative impact on Rev Req		(5,922)	(4,711)	(3,171)	(4,193)	(5,156)	(5,371)	(5,420)	(5,603)	(5,932)	(6,062)	(6,004)	(5,946)	(5,888)	(5,830)	(5,773)	(5,715)	(5,657)	(5,599)	(5,541)	(5,484)	(5,727)		
Net Present Value		(59,962)																						
Bonus deducted in 2014 (As Filed Pre Law Change)																								
Bonus		-																						-
NOL																								-
MARSC 20 for 2014 assets		(5,814)	(11,192)	(10,352)	(9,577)	(8,857)	(8,194)	(7,578)	(7,011)	(6,918)	(6,918)	(6,918)	(6,918)	(6,918)	(6,918)	(6,918)	(6,916)	(6,918)	(6,916)	(6,918)	(6,916)	(3,459)		(155,044)
MARSC 20 for 2015 assets			(4,210)	(8,105)	(7,497)	(6,935)	(6,414)	(5,934)	(5,488)	(5,077)	(5,010)	(5,008)	(5,010)	(5,008)	(5,010)	(5,008)	(5,010)	(5,008)	(5,010)	(5,008)	(5,010)	(5,008)	(2,505)	(112,275)
Straight Line 7 yrs for 2015 assets			-	-	-	-	-	-	-	-														-
Book Depreciation		7,752	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	13,366	5,614	10,158	277,476
Cash Tax Benefit Timing Differences		678	(713)	(1,782)	(1,298)	(849)	(435)	(51)	303	480	503	504	503	504	503	504	504	504	504	504	504	(999)	2,679	(93,561)
Section 199 Deduction		(5,543)	(9,280)	(6,075)	(7,681)	(9,274)	(9,579)	(9,659)	(9,733)	(10,111)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,699)		(202,655)
Cash Tax Benefit for Section 199		(1,940)	(3,248)	(2,126)	(2,688)	(3,246)	(3,353)	(3,381)	(3,407)	(3,539)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,745)		(70,929)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base		678	(713)	(1,782)	(1,298)	(849)	(435)	(51)	303	480	503	504	503	504	503	504	504	504	504	504	504	(999)	2,679	3,555
Cost of Capital		0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact		50	(53)	(132)	(96)	(63)	(32)	(4)	22	35	37	37	37	37	37	37	37	37	37	37	37	(74)		65
Pro forma NOI impact		(1,940)	(3,248)	(2,126)	(2,688)	(3,246)	(3,353)	(3,381)	(3,407)	(3,539)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,660)	(3,745)		(70,929)
Gross Up Factor		0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req		82	(5,133)	(3,511)	(4,329)	(5,145)	(5,263)	(5,263)	(5,263)	(5,448)	(5,633)	(5,633)	(5,633)	(5,633)	(5,633)	(5,633)	(5,633)	(5,633)	(5,633)	(5,633)	(5,633)	(5,938)		(107,178)
Cumulative impact on Rev Req		82	(5,051)	(3,511)	(4,534)	(5,499)	(5,714)	(5,764)	(5,769)	(5,920)	(6,050)	(5,993)	(5,935)	(5,877)	(5,819)	(5,761)	(5,704)	(5,646)	(5,588)	(5,530)	(5,472)	(5,719)		
Net Present Value		(55,614)																						

Discount Rate 7.38%

Assume for this analysis that book depreciation will be 20 yr straight line property.

LG&E																							
(In $000)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Total Company (Bonus 2014)																							
Taxable Inc (Loss) pre Sect 199 and Bonus	70,162	242,199	221,227	167,110	198,129	229,045	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	4,864,528
Bonus		(312,361)																					(312,361)
MARSC 20 for 2015 assets			(10,346)	(19,917)	(17,042)	(15,762)	(14,581)	(13,486)	(12,476)	(12,311)	(12,308)	(12,311)	(12,308)	(12,311)	(12,308)	(12,311)	(12,308)	(12,311)	(12,308)	(12,311)	(12,308)	(12,311)	(263,633)
NOL	(70,162)	70,162			-																		-
Section 199		-	(10,228)	(7,139)	(8,783)	(10,344)	(10,620)	(10,673)	(10,722)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(10,730)	(207,994)
Taxable Inc (Loss)	-	-	200,653	140,054	172,304	202,939	208,340	209,382	210,343	210,501	210,503	210,501	210,503	210,501	210,503	210,501	210,503	210,501	210,503	210,501	210,503	210,501	4,080,540
Total Company (Bonus 2014 and 2015)																							
Taxable Inc (Loss) pre Sect 199 and Bonus	124,835	242,199	221,227	167,110	198,129	229,045	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	4,919,201
Bonus		(312,361)	(275,900)																				(588,261)
NOL	(124,835)	70,162	54,673																				-
Section 199		-	-	(8,105)	(9,609)	(11,109)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(11,327)	(210,051)
Taxable Inc (Loss)	-	-	-	159,005	188,520	217,936	222,214	222,214	222,214	222,214	222,214	222,214	222,214	222,214	222,214	222,214	222,214	222,214	222,214	222,214	222,214	222,214	4,120,889
Total Company (Elect no bonus)																							
Taxable Inc (Loss) pre Sect 199 and Bonus	124,835	242,199	221,227	167,110	198,129	229,045	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	4,919,201
MARSC 20 in place of bonus		(8,174)	(15,735)	(14,554)	(13,464)	(12,453)	(11,520)	(10,654)	(9,857)	(9,726)	(9,724)	(9,726)	(9,724)	(9,726)	(9,724)	(9,726)	(9,724)	(9,726)	(9,724)	(9,726)	(9,724)	(4,863)	(217,968)
Straight Line 7 yrs in place of bonus		(6,742)	(13,485)	(13,485)	(13,485)	(13,485)	(13,485)	(13,485)	(6,742)														(94,393)
MARSC 20 in place of bonus			(6,665)	(12,830)	(11,867)	(10,978)	(10,154)	(9,393)	(8,687)	(8,037)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(173,762)
Straight Line 7 yrs in place of bonus			(7,012)	(14,025)	(14,025)	(14,025)	(14,025)	(14,025)	(14,025)	(7,012)													(98,173)
Section 199	(6,054)	(11,023)	(8,649)	(5,443)	(7,047)	(8,638)	(8,941)	(9,020)	(9,420)	(10,125)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,471)	(10,706)	(210,243)
Taxable Inc (Loss)	118,781	216,260	169,681	106,774	138,242	169,467	175,417	176,964	184,810	198,641	205,417	205,416	205,417	205,416	205,417	205,416	205,417	205,416	205,417	205,416	205,417	210,043	4,124,662
Total Company (Bonus as filed case)																							
Taxable Inc (Loss) pre Sect 199 and Bonus	124,835	210,599	221,227	167,110	198,129	229,045	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	233,541	4,887,601
Bonus		(87,887)																					(87,887)
MARSC 20 in place of bonus		(8,418)	(16,205)	(14,988)	(13,866)	(12,824)	(11,863)	(10,972)	(10,151)	(10,016)	(10,016)	(10,016)	(10,016)	(10,016)	(10,016)	(10,016)	(10,014)	(10,016)	(10,014)	(10,016)	(10,014)	(5,008)	(224,481)
MARSC 20 in place of bonus 2015			(6,665)	(12,830)	(11,867)	(10,978)	(10,154)	(9,393)	(8,687)	(8,037)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(7,930)	(7,928)	(173,762)
Straight Line 7 yrs in place of bonus 2015			(7,012)	(14,025)	(14,025)	(14,025)	(14,025)	(14,025)	(14,025)	(7,012)	-	-	-	-	-	-	-	-	-	-	-	-	(98,173)
Section 199	(6,054)	(5,543)	(9,280)	(6,075)	(7,681)	(9,274)	(9,579)	(9,659)	(9,733)	(10,111)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,456)	(10,699)	(208,710)
Taxable Inc (Loss)	118,781	108,751	182,065	119,192	150,691	181,944	187,921	189,492	190,945	198,365	205,138	205,140	205,138	205,140	205,138	205,140	205,141	205,140	205,141	205,140	205,141	209,905	4,094,589

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(In $000)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Total Company																								
Bonus deducted in 2014																								
Bonus		(400,222)																						(400,222)
NOL	(174,730)	205,024	(30,294)																					-
MARSC 20 for 2015 assets			(11,480)	(22,100)	(20,440)	(18,910)	(17,489)	(16,179)	(14,964)	(13,843)	(13,660)	(13,656)	(13,660)	(13,656)	(13,660)	(13,656)	(13,660)	(13,656)	(13,660)	(13,656)	(13,660)	(13,656)	(6,830)	(306,130)
Straight Line 7 yrs for 2015 assets			(7,054)	(14,108)	(14,108)	(14,108)	(14,108)	(14,108)	(14,108)	(7,054)														(98,757)
Book Depreciation		20,011	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	20,244		805,109
Cash Tax Benefit Timing Differences	(61,156)	(61,315)	(3,000)	1,417	1,997	2,533	3,030	3,489	3,914	6,775	9,309	9,310	9,309	9,310	9,309	9,310	9,309	9,310	9,309	9,310	9,309	2,306	(2,390)	-
Section 199 Deduction	10,484	-	(11,219)	(10,874)	(14,480)	(15,145)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)		(273,525)
Cash Tax Benefit for Section 199	3,669	-	(3,927)	(3,806)	(5,068)	(5,301)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)		(95,734)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base	(61,156)	(61,315)	(3,000)	1,417	1,997	2,533	3,030	3,489	3,914	6,775	9,309	9,310	9,309	9,310	9,309	9,310	9,309	9,310	9,309	9,310	9,309	2,306	(2,390)	-
Cost of Capital	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact	(4,513)	(4,525)	(221)	105	147	187	224	257	289	500	687	687	687	687	687	687	687	687	687	687	687	170		-
Pro forma NOI impact	3,669	-	(3,927)	(3,806)	(5,068)	(5,301)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)		(95,734)
Gross Up Factor	0.61334	0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req	(1,376)	(7,378)	(6,450)	(5,756)	(7,652)	(7,952)	(7,554)	(7,501)	(7,453)	(7,124)	(6,834)	(6,833)	(6,834)	(6,833)	(6,834)	(6,833)	(6,834)	(6,833)	(6,834)	(6,833)	(6,834)	(7,637)		(149,002)
Cumulative impact on Rev Req		(7,378)	(21,187)	(20,836)	(22,570)	(22,641)	(21,952)	(21,552)	(21,103)	(20,325)	(19,257)	(18,188)	(17,120)	(16,052)	(14,983)	(13,915)	(12,847)	(11,778)	(10,710)	(9,642)	(8,573)	(8,309)		
Net Present Value		(198,631)																						
Bonus deducted in 2014 and 2015																								
Bonus		(400,222)	(404,887)																					(805,109)
NOL	(174,730)	205,024	175,429	(205,723)																				-
Book Depreciation		20,011	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	20,244		805,109
Cash Tax Benefit Timing Differences	(61,156)	(61,315)	(66,221)	(57,914)	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	7,086	-	0
Section 199 Deduction	10,484	-	(0)	(284)	(16,102)	(16,646)	(15,906)	(15,802)	(15,706)	(15,617)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)		(272,803)
Cash Tax Benefit for Section 199	3,669	-	(0)	(99)	(5,636)	(5,826)	(5,567)	(5,531)	(5,497)	(5,466)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)		(95,481)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base	(61,156)	(61,315)	(66,221)	(57,914)	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	14,089	7,086		0
Cost of Capital	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact	(4,513)	(4,525)	(4,887)	(4,274)	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	1,040	523		0
Pro forma NOI impact	3,669	-	(0)	(99)	(5,636)	(5,826)	(5,567)	(5,531)	(5,497)	(5,466)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)		(95,481)
Gross Up Factor	0.61334	0.61334	0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req	(1,376)	(7,378)	(7,968)	(6,801)	(7,147)	(7,443)	(7,040)	(6,984)	(6,931)	(6,883)	(6,875)	(6,875)	(6,875)	(6,875)	(6,875)	(6,875)	(6,875)	(6,875)	(6,875)	(6,875)	(6,875)	(7,679)		(149,252)
Loss of Sect 199 on gross up factor for NOI filed																								
NOI Deficiency as filed			96,000																					
Difference in gross up factor (1.64112-1.59183)			0.04929																					
Revenue Impact			4,732																					4,732
Estimated Rev Req impact from loss of Sect 199 on gross up factor (ECR)		5,000	5,000																					10,000
Cumulative impact on Rev Req		(2,378)	(12,972)	(29,505)	(36,498)	(35,176)	(33,157)	(31,483)	(29,814)	(28,149)	(26,524)	(24,907)	(23,290)	(21,673)	(20,056)	(18,439)	(16,822)	(15,205)	(13,588)	(11,971)	(10,354)	(9,541)		
Net Present Value		(258,963)																						
No Bonus deducted in 2014 and 2015																								
MARSC 20 in place of bonus		(8,373)	(27,598)	(37,008)	(34,232)	(31,665)	(29,289)	(27,093)	(25,060)	(23,806)	(23,620)	(23,619)	(23,620)	(23,619)	(23,620)	(23,619)	(23,620)	(23,619)	(23,620)	(23,619)	(23,620)	(18,638)	(6,830)	(529,405)
Straight Line 7 yrs in place of bonus		(12,639)	(32,332)	(39,386)	(39,386)	(39,386)	(39,386)	(39,386)	(26,747)	(7,054)														(275,704)
Book Depreciation		20,011	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	20,244		805,109
Cash Tax Benefit Timing Differences		(350)	(6,886)	(12,648)	(11,677)	(10,779)	(9,947)	(9,178)	(4,043)	3,288	5,822	5,823	5,822	5,823	5,822	5,823	5,822	5,823	5,822	5,823	5,822	562	(2,390)	0
Section 199		(10,451)	(10,553)	(8,463)	(12,136)	(12,863)	(12,294)	(12,347)	(13,154)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(14,219)		(273,524)
Cash Tax Benefit for Section 199	-	(3,658)	(3,693)	(2,962)	(4,248)	(4,502)	(4,303)	(4,321)	(4,604)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,977)		(95,734)
Reduce Capitalization/Rate Base	-	(350)	(6,886)	(12,648)	(11,677)	(10,779)	(9,947)	(9,178)	(4,043)	3,288	5,822	5,823	5,822	5,823	5,822	5,823	5,822	5,823	5,822	5,823	5,822	562		0
Cost of Capital	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact	-	(26)	(508)	(933)	(862)	(795)	(734)	(677)	(298)	243	430	430	430	430	430	430	430	430	430	430	430	41		0
Pro forma NOI impact	-	(3,658)	(3,693)	(2,962)	(4,248)	(4,502)	(4,303)	(4,321)	(4,604)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,977)		(95,734)
Gross Up Factor	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		0.64306
Bonus impact on Rev Req	-	(5,728)	(6,534)	(6,058)	(7,945)	(8,238)	(7,833)	(7,773)	(7,623)	(7,199)	(6,908)	(6,908)	(6,908)	(6,908)	(6,908)	(6,908)	(6,908)	(6,908)	(6,908)	(6,908)	(6,908)	(7,675)		(148,597)
Cumulative impact on Rev Req		(5,728)	(6,574)	(6,888)	(10,227)	(11,860)	(12,692)	(13,774)	(14,677)	(14,717)	(14,049)	(13,381)	(12,712)	(12,044)	(11,376)	(10,708)	(10,040)	(9,371)	(8,703)	(8,035)	(7,367)	(7,465)		
Net Present Value		(118,458)																						
Bonus deducted in 2014 (As Filed Pre Law Change)																								
Bonus		(204,324)																						(204,324)
NOL																								-
MARSC 20 for 2014 assets		(7,346)	(14,142)	(13,080)	(12,101)	(11,192)	(10,353)	(9,575)	(8,859)	(8,741)	(8,741)	(8,741)	(8,741)	(8,741)	(8,741)	(8,741)	(8,739)	(8,741)	(8,739)	(8,741)	(8,739)	(4,370)		(195,904)
MARSC 20 for 2015 assets			(11,480)	(22,100)	(20,440)	(18,910)	(17,489)	(16,179)	(14,964)	(13,843)	(13,660)	(13,656)	(13,660)	(13,656)	(13,660)	(13,656)	(13,660)	(13,656)	(13,660)	(13,656)	(13,660)	(13,656)	(6,830)	(306,130)
Straight Line 7 yrs for 2015 assets			(7,054)	(14,108)	(14,108)	(14,108)	(14,108)	(14,108)	(14,108)	(7,054)	-	-	-	-	-	-	-	-	-	-	-	-	-	(98,757)
Book Depreciation		20,011	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	40,255	20,244		805,109
Cash Tax Benefit Timing Differences		(67,081)	2,653	(3,161)	(2,238)	(1,384)	(593)	137	814	3,716	6,249	6,250	6,249	6,250	6,249	6,250	6,250	6,250	6,250	6,250	6,250	776	(2,390)	(281,790)
Section 199 Deduction		17	(12,188)	(10,089)	(13,754)	(14,474)	(13,897)	(13,944)	(13,987)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(14,256)		(274,496)
Cash Tax Benefit for Section 199		6	(4,266)	(3,531)	(4,814)	(5,066)	(4,864)	(4,880)	(4,895)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,990)		(96,074)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base		(67,081)	2,653	(3,161)	(2,238)	(1,384)	(593)	137	814	3,716	6,249	6,250	6,249	6,250	6,249	6,250	6,250	6,250	6,250	6,250	6,250	776	(2,390)	(2)
Cost of Capital		0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact		(4,951)	196	(233)	(165)	(102)	(44)	10	60	274	461	461	461	461	461	461	461	461	461	461	461	57		176
Pro forma NOI impact		6	(4,266)	(3,531)	(4,814)	(5,066)	(4,864)	(4,880)	(4,895)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,990)		(96,074)
Gross Up Factor		0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req		(8,071)	(6,329)	(5,854)	(7,743)	(8,036)	(7,632)	(7,573)	(7,519)	(7,190)	(6,899)	(6,899)	(6,899)	(6,899)	(6,899)	(6,899)	(6,899)	(6,899)	(6,899)	(6,899)	(6,899)	(7,670)		(149,508)
Cumulative impact on Rev Req		(8,071)	(14,401)	(13,621)	(15,873)	(16,423)	(16,177)	(16,187)	(16,117)	(15,694)	(14,977)	(14,260)	(13,543)	(12,825)	(12,108)	(11,391)	(10,674)	(9,956)	(9,239)	(8,522)	(7,804)	(7,858)		
Net Present Value		(150,445)																						
Discount Rate		7.38%																						

Assume for this analysis that book depreciation will be 20 yr straight line property.

KU	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
(In $000)																								
ECR																								
Bonus deducted in 2014																								
Bonus		(294,911)																						(294,911)
MARSC 20 in place of bonus (40%)			(2,469)	(4,753)	(4,396)	(4,067)	(3,761)	(3,480)	(3,218)	(2,977)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(1,469)	(65,842)
Straight Line 7 yrs in place of bonus (60%)			(7,054)	(14,108)	(14,108)	(14,108)	(14,108)	(14,108)	(14,108)	(7,054)														(98,757)
Book Depreciation		14,746	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	8,230		459,506
Cash Tax Benefit Timing Differences		(98,058)	4,708	1,440	1,565	1,680	1,787	1,886	1,977	4,530	7,013	7,013	7,013	7,013	7,013	7,013	7,013	7,013	7,013	7,013	7,013	1,852	(514)	(1)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base		(98,058)	4,708	1,440	1,565	1,680	1,787	1,886	1,977	4,530	7,013	7,013	7,013	7,013	7,013	7,013	7,013	7,013	7,013	7,013	7,013	1,852	(514)	(1)
Cost of Capital		0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738
NOI Found reasonable impact		(7,237)	347	106	115	124	132	139	146	334	518	518	518	518	518	518	518	518	518	518	518	137	(38)	(0)
Gross Up Factor		0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	
Bonus impact on Rev Req		(11,799)	540	165	180	193	205	216	227	520	805	805	805	805	805	805	805	805	805	805	805	213	(59)	(487)
Cumulative impact on Rev Req		(11,799)	(11,258)	(11,093)	(10,914)	(10,721)	(10,516)	(10,299)	(10,072)	(9,552)	(8,748)	(7,943)	(7,138)	(6,333)	(5,528)	(4,723)	(3,918)	(3,114)	(2,309)	(1,504)	(699)	(487)		
Net Present Value		(96,532)																						
Bonus deducted in 2014 and 2015																								
Bonus		(294,911)	(164,595)																					(459,506)
Book Depreciation		14,746	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	8,230	16,680	476,186
Cash Tax Benefit Timing Differences		(98,058)	(49,567)	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	2,880	5,838	(0)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base		(98,058)	(49,567)	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	8,041	2,880		(0)
Cost of Capital		0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact		(7,237)	(3,658)	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	593	213		(0)
Gross Up Factor		0.61334	0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req		(11,799)	(5,964)	923	923	923	923	923	923	923	923	923	923	923	923	923	923	923	923	923	923	331		(821)
Estimated Rev Req impact from loss of Sect 199 on gross up factor (ECR)		5,000	5,000																					
Cumulative impact on Rev Req		(6,799)	(12,763)	(16,840)	(15,917)	(14,994)	(14,072)	(13,149)	(12,226)	(11,303)	(10,380)	(9,457)	(8,534)	(7,612)	(6,689)	(5,766)	(4,843)	(3,920)	(2,997)	(2,074)	(1,152)	(821)		
Net Present Value		(116,588)																						
No Bonus deducted in 2014 and 2015																								
MARSC 20 in place of bonus (40%)		(4,424)	(10,985)	(12,629)	(11,683)	(10,806)	(9,996)	(9,246)	(8,553)	(8,241)	(8,200)	(8,201)	(8,200)	(8,201)	(8,200)	(8,201)	(8,200)	(8,201)	(8,200)	(8,201)	(8,200)	(5,569)	(1,469)	(183,802)
Straight Line 7 yrs in place of bonus (60%)		(12,639)	(32,332)	(39,386)	(39,386)	(39,386)	(39,386)	(39,386)	(26,747)	(7,054)														(275,704)
Book Depreciation		14,746	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	8,230	16,680	476,186
Cash Tax Benefit Timing Differences		(811)	(7,120)	(10,164)	(9,833)	(9,526)	(9,242)	(8,980)	(4,314)	2,688	5,171	5,171	5,171	5,171	5,171	5,171	5,171	5,171	5,171	5,171	5,171	931	5,324	5,838
Reduce Capitalization/Rate Base		(811)	(7,120)	(10,164)	(9,833)	(9,526)	(9,242)	(8,980)	(4,314)	2,688	5,171	5,171	5,171	5,171	5,171	5,171	5,171	5,171	5,171	5,171	5,171	931	5,324	5,838
Cost of Capital		0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738
NOI Found reasonable impact		(60)	(525)	(750)	(726)	(703)	(682)	(663)	(318)	198	382	382	382	382	382	382	382	382	382	382	382	69	393	431
Gross Up Factor		0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306
Bonus impact on Rev Req		(93)	(817)	(1,166)	(1,128)	(1,093)	(1,061)	(1,031)	(495)	309	593	593	593	593	593	593	593	593	593	593	593	107	611	59
Cumulative impact on Rev Req		(93)	(910)	(2,077)	(3,205)	(4,298)	(5,359)	(6,390)	(6,885)	(6,576)	(5,983)	(5,389)	(4,796)	(4,202)	(3,609)	(3,015)	(2,422)	(1,828)	(1,235)	(641)	(48)	59		
Net Present Value		(38,667)																						
Bonus deducted in 2014 (As Filed Pre Law Change)																								
Bonus		(204,324)																						(204,324)
MARSC 20 for 2014 assets		(3,397)	(6,539)	(6,048)	(5,596)	(5,175)	(4,788)	(4,428)	(4,096)	(4,042)	(4,042)	(4,042)	(4,042)	(4,042)	(4,042)	(4,042)	(4,041)	(4,042)	(4,041)	(4,042)	(4,041)	(2,021)		(90,590)
MARSC 20 for 2015 assets			(2,469)	(4,753)	(4,396)	(4,067)	(3,761)	(3,480)	(3,218)	(2,977)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(2,938)	(1,469)	(65,842)
Straight Line 7 yrs for 2015 assets			(7,054)	(14,108)	(14,108)	(14,108)	(14,108)	(14,108)	(14,108)	(7,054)	-	-	-	-	-	-	-	-	-	-	-	-		(98,757)
Book Depreciation		14,746	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	22,975	8,230	16,680	476,186
Cash Tax Benefit Timing Differences		(67,541)	2,419	(677)	(394)	(131)	111	336	543	3,116	5,598	5,598	5,598	5,598	5,598	5,598	5,599	5,598	5,599	5,598	5,599	1,145	5,324	5,836
Reduce Capitalization/Rate Base		(67,541)	2,419	(677)	(394)	(131)	111	336	543	3,116	5,598	5,598	5,598	5,598	5,598	5,598	5,599	5,598	5,599	5,598	5,599	1,145	5,324	5,836
Cost of Capital		0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738
NOI Found reasonable impact		(4,985)	179	(50)	(29)	(10)	8	25	40	230	413	413	413	413	413	413	413	413	413	413	413	84	393	431
Gross Up Factor		0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	
Bonus impact on Rev Req		(8,127)	278	(78)	(45)	(15)	13	39	62	358	642	642	642	642	642	642	643	642	643	642	643	131	611	(317)
Cumulative impact on Rev Req		(8,127)	(7,849)	(7,927)	(7,972)	(7,987)	(7,974)	(7,936)	(7,873)	(7,516)	(6,873)	(6,231)	(5,588)	(4,946)	(4,303)	(3,661)	(3,018)	(2,376)	(1,733)	(1,091)	(448)	(317)		
Net Present Value		(71,757)																						
Discount Rate		7.38%																						

Assume for this analysis that book depreciation will be
20 yr straight line property.

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(In $000)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Base																								
Bonus deducted in 2014																								
Bonus		(105,311)																						(105,311)
NOL	(174,730)	205,024	(30,294)																					-
MARSC 20 for 2015 assets			(9,011)	(17,347)	(16,044)	(14,843)	(13,728)	(12,699)	(11,745)	(10,866)	(10,722)	(10,719)	(10,722)	(10,719)	(10,722)	(10,719)	(10,722)	(10,719)	(10,722)	(10,719)	(10,722)	(10,719)	(5,361)	(240,288)
Straight Line 7 yrs for 2015 assets			-	-	-	-	-	-	-	-														-
Book Depreciation		5,266	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	12,015		345,603
Cash Tax Benefit Timing Differences	(61,156)	36,742	(7,709)	(23)	433	853	1,243	1,603	1,937	2,245	2,295	2,296	2,295	2,296	2,295	2,296	2,295	2,296	2,295	2,296	2,295	454	(1,876)	1
Section 199 Deduction	10,484	-	(11,219)	(10,874)	(14,480)	(15,145)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)		(273,525)
Cash Tax Benefit for Section 199	3,669	-	(3,927)	(3,806)	(5,068)	(5,301)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)		(95,734)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base	(61,156)	36,742	(7,709)	(23)	433	853	1,243	1,603	1,937	2,245	2,295	2,296	2,295	2,296	2,295	2,296	2,295	2,296	2,295	2,296	2,295	454	(1,876)	1
Cost of Capital	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact	(4,513)	2,712	(569)	(2)	32	63	92	118	143	166	169	169	169	169	169	169	169	169	169	169	169	33		0
Pro forma NOI impact	3,669	-	(3,927)	(3,806)	(5,068)	(5,301)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)	(5,081)		(95,734)
Gross Up Factor	0.61334	0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req	(1,376)	4,421	(6,991)	(5,921)	(7,831)	(8,145)	(7,759)	(7,718)	(7,680)	(7,644)	(7,638)	(7,638)	(7,638)	(7,638)	(7,638)	(7,638)	(7,638)	(7,638)	(7,638)	(7,638)	(7,638)	(7,850)		(148,515)
Cumulative impact on Rev Req		4,421	(9,928)	(9,743)	(11,656)	(11,920)	(11,436)	(11,252)	(11,030)	(10,772)	(10,509)	(10,246)	(9,982)	(9,719)	(9,455)	(9,192)	(8,928)	(8,665)	(8,401)	(8,138)	(7,874)	(7,822)		
Net Present Value		(102,099)																						
Bonus deducted in 2014 and 2015																								
Bonus		(105,311)	(240,292)																					(345,603)
NOL	(174,730)	205,024	175,429	(205,723)	-																			-
Book Depreciation		5,266	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	12,015	12,545	358,148
Cash Tax Benefit Timing Differences	(61,156)	36,742	(16,654)	(65,955)	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	4,205	4,391	0
Section 199 Deduction	10,484	-	(0)	(284)	(16,102)	(16,646)	(15,906)	(15,802)	(15,706)	(15,617)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)		(272,803)
Cash Tax Benefit for Section 199	3,669	-	(0)	(99)	(5,636)	(5,826)	(5,567)	(5,531)	(5,497)	(5,466)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)		(95,481)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base	(61,156)	36,742	(16,654)	(65,955)	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	6,048	4,205		0
Cost of Capital	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact	(4,513)	2,712	(1,229)	(4,867)	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446	446	310		0
Pro forma NOI impact	3,669	-	(0)	(99)	(5,636)	(5,826)	(5,567)	(5,531)	(5,497)	(5,466)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)	(5,461)		(95,481)
Gross Up Factor	0.61334	0.61334	0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req	(1,376)	4,421	(2,004)	(7,724)	(8,070)	(8,366)	(7,963)	(7,907)	(7,854)	(7,806)	(7,798)	(7,798)	(7,798)	(7,798)	(7,798)	(7,798)	(7,798)	(7,798)	(7,798)	(7,798)	(7,798)	(8,009)		(148,431)
Loss of Sect 199 on gross up factor for NOI filed																								
NOI Deficiency as filed			96,000																					
Difference in gross up factor (1.64112-1.59183)			0.04929																					
Revenue Impact			4,732																					
Cumulative impact on Rev Req		4,421	(210)	(12,665)	(20,580)	(20,182)	(19,086)	(18,335)	(17,588)	(16,846)	(16,144)	(15,449)	(14,756)	(14,061)	(13,367)	(12,673)	(11,979)	(11,285)	(10,591)	(9,897)	(9,203)	(8,720)		
Net Present Value		(142,376)																						
No Bonus deducted in 2014 and 2015																								
MARSC 20 in place of bonus		(3,949)	(16,613)	(24,378)	(22,549)	(20,859)	(19,294)	(17,847)	(16,508)	(15,565)	(15,420)	(15,418)	(15,420)	(15,418)	(15,420)	(15,418)	(15,420)	(15,418)	(15,420)	(15,418)	(15,420)	(13,069)	(5,361)	(345,603)
Straight Line 7 yrs in place of bonus		-	-	-	-	-	-	-	-	-														-
Book Depreciation		5,266	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	12,015	12,545	358,148
Cash Tax Benefit Timing Differences		461	233	(2,484)	(1,844)	(1,253)	(705)	(198)	270	600	651	652	651	652	651	652	651	652	651	652	651	(369)	2,515	4,391
Section 199	-	(10,451)	(10,553)	(8,463)	(12,136)	(12,863)	(12,294)	(12,347)	(13,154)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(13,920)	(14,219)		(273,524)
Cash Tax Benefit for Section 199		(3,658)	(3,693)	(2,962)	(4,248)	(4,502)	(4,303)	(4,321)	(4,604)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,977)		(95,734)
Reduce Capitalization/Rate Base	-	461	233	(2,484)	(1,844)	(1,253)	(705)	(198)	270	600	651	652	651	652	651	652	651	652	651	652	651	(369)		4,391
Cost of Capital	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact	-	34	17	(183)	(136)	(92)	(52)	(15)	20	44	48	48	48	48	48	48	48	48	48	48	48	(27)		324
Pro forma NOI impact	-	(3,658)	(3,693)	(2,962)	(4,248)	(4,502)	(4,303)	(4,321)	(4,604)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,872)	(4,977)		(95,734)
Gross Up Factor	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		0.64306
Bonus impact on Rev Req	-	(5,635)	(5,717)	(4,891)	(6,817)	(7,145)	(6,772)	(6,743)	(7,128)	(7,508)	(7,502)	(7,502)	(7,502)	(7,502)	(7,502)	(7,502)	(7,502)	(7,502)	(7,502)	(7,502)	(7,502)	(7,782)		(148,656)
Cumulative impact on Rev Req		(5,635)	(5,664)	(4,811)	(7,022)	(7,562)	(7,333)	(7,384)	(7,793)	(8,141)	(8,066)	(7,992)	(7,917)	(7,842)	(7,767)	(7,693)	(7,618)	(7,543)	(7,468)	(7,394)	(7,319)	(7,524)		
Net Present Value		(79,791)																						
Bonus deducted in 2014 (As Filed Pre Law Change)																								
Bonus		-																						-
NOL																								-
MARSC 20 for 2014 assets		(3,949)	(7,602)	(7,032)	(6,505)	(6,016)	(5,566)	(5,148)	(4,762)	(4,699)	(4,699)	(4,699)	(4,699)	(4,699)	(4,699)	(4,699)	(4,698)	(4,699)	(4,698)	(4,699)	(4,698)	(2,349)		(105,314)
MARSC 20 for 2015 assets			(9,011)	(17,347)	(16,044)	(14,843)	(13,728)	(12,699)	(11,745)	(10,866)	(10,722)	(10,719)	(10,722)	(10,719)	(10,722)	(10,719)	(10,722)	(10,719)	(10,722)	(10,719)	(10,722)	(10,719)	(5,361)	(240,288)
Straight Line 7 yrs for 2015 assets			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Book Depreciation		5,266	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	17,280	12,015	12,545	358,148
Cash Tax Benefit Timing Differences		461	233	(2,484)	(1,844)	(1,253)	(705)	(198)	270	600	651	652	651	652	651	652	651	652	651	652	651	(369)	2,515	(120,961)
Section 199 Deduction		17	(12,188)	(10,089)	(13,754)	(14,474)	(13,897)	(13,944)	(13,987)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(14,256)		(274,496)
Cash Tax Benefit for Section 199		6	(4,266)	(3,531)	(4,814)	(5,066)	(4,864)	(4,880)	(4,895)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,990)		(96,074)
Revenue Requirement Impact																								
Reduce Capitalization/Rate Base		461	233	(2,484)	(1,844)	(1,253)	(705)	(198)	270	600	651	652	651	652	651	652	651	652	651	652	651	(369)	2,515	4,391
Cost of Capital		0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738	0.0738		0.0738
NOI Found reasonable impact		34	17	(183)	(136)	(92)	(52)	(15)	20	44	48	48	48	48	48	48	48	48	48	48	48	(27)		138
Pro forma NOI impact		6	(4,266)	(3,531)	(4,814)	(5,066)	(4,864)	(4,880)	(4,895)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,898)	(4,990)		(96,074)
Gross Up Factor		0.61334	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306	0.64306		
Bonus impact on Rev Req		55	(6,607)	(5,776)	(7,698)	(8,021)	(7,645)	(7,612)	(7,582)	(7,547)	(7,542)	(7,542)	(7,542)	(7,542)	(7,542)	(7,542)	(7,542)	(7,542)	(7,542)	(7,542)	(7,542)	(7,801)		(149,191)
Cumulative impact on Rev Req		55	(6,551)	(5,694)	(7,900)	(8,436)	(8,203)	(8,251)	(8,243)	(8,178)	(8,104)	(8,029)	(7,954)	(7,879)	(7,805)	(7,730)	(7,655)	(7,580)	(7,506)	(7,431)	(7,356)	(7,541)		
Net Present Value		(78,688)																						
Discount Rate		7.38%																						

Assume for this analysis that book depreciation will be 20 yr straight line property.

KU

(In $000)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Total Company																							
Taxable Inc (Loss) pre Sect 199 and Bonus	174,730	195,198	217,275	181,230	241,336	252,417	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	5,133,706
Bonus		(400,222)																					(400,222)
NOL	(174,730)	205,024	(30,294)																				-
Section 199		-	(11,219)	(10,874)	(14,480)	(15,145)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(14,518)	(284,009)
Taxable Inc (Loss)	-	-	175,762	170,356	226,856	237,272	227,452	227,452	227,452	227,452	227,452	227,452	227,452	227,452	227,452	227,452	227,452	227,452	227,452	227,452	227,452	227,452	4,449,475
Total Company (Bonus 2014 and 2015)																							
Taxable Inc (Loss) pre Sect 199 and Bonus	174,730	195,198	217,275	181,230	241,336	252,417	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	5,133,706
Bonus		(400,222)	(407,887)																				(808,109)
MARSC 20 for 2015 assets			15,183	29,229	27,034	25,010	23,131	21,398	19,791	18,309	18,066	18,062	18,066	18,062	18,066	18,062	18,066	18,062	18,066	18,062	18,066	18,062	395,854
NOL	(174,730)	205,024	175,429	(205,723)	-																		-
Section 199		-	(0)	(284)	(16,102)	(16,646)	(15,906)	(15,802)	(15,706)	(15,617)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(15,602)	(283,287)
Taxable Inc (Loss)	-	-	0	4,452	252,268	260,781	249,195	247,566	246,055	244,662	244,434	244,430	244,434	244,430	244,434	244,430	244,434	244,430	244,434	244,430	244,434	244,430	4,438,164
Total Company (Elect no bonus)																							
Taxable Inc (Loss) pre Sect 199 and Bonus	174,730	195,198	217,275	181,230	241,336	252,417	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	5,133,706
MARSC 20 in place of bonus		(8,373)	(16,118)	(14,908)	(13,792)	(12,756)	(11,800)	(10,914)	(10,096)	(9,963)	(9,960)	(9,963)	(9,960)	(9,963)	(9,960)	(9,963)	(9,960)	(9,963)	(9,960)	(9,963)	(9,960)	(4,981)	(223,275)
Straight Line 7 yrs in place of bonus		(12,639)	(25,278)	(25,278)	(25,278)	(25,278)	(25,278)	(25,278)	(12,639)														(176,946)
Section 199	(10,484)	(10,451)	(10,553)	(8,463)	(12,136)	(12,863)	(12,294)	(12,347)	(13,154)	(13,920)	(13,921)	(13,920)	(13,921)	(13,920)	(13,921)	(13,920)	(13,921)	(13,920)	(13,921)	(13,920)	(13,921)	(14,219)	(284,009)
Taxable Inc (Loss)	164,246	163,735	165,326	132,581	190,130	201,520	192,598	193,432	206,080	218,087	218,089	218,087	218,089	218,087	218,089	218,087	218,089	218,087	218,089	218,087	218,089	222,769	4,449,476
Total Company (Bonus as filed case)																							
Taxable Inc (Loss) pre Sect 199 and Bonus	174,730	211,390	217,275	181,230	241,336	252,417	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	241,970	5,149,898
Bonus		(204,324)																					(204,324)
MARSC 20 in place of bonus		(7,346)	(14,142)	(13,080)	(12,101)	(11,192)	(10,353)	(9,575)	(8,859)	(8,741)	(8,741)	(8,741)	(8,741)	(8,741)	(8,741)	(8,741)	(8,739)	(8,741)	(8,739)	(8,741)	(8,739)	(4,370)	(195,904)
Straight Line 7 yrs in place of bonus																							-
Section 199	(10,484)	17	(12,188)	(10,089)	(13,754)	(14,474)	(13,897)	(13,944)	(13,987)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(13,994)	(14,256)	(284,980)
Taxable Inc (Loss)	164,246	(263)	190,945	158,061	215,481	226,752	217,720	218,451	219,125	219,235	219,235	219,235	219,235	219,235	219,235	219,235	219,237	219,235	219,237	219,235	219,237	223,344	4,464,690

LG&E KU
PPL companies

Employee Bulletin

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March 19, 2015

LG&E and KU 2015 Team Incentive Award measures, weightings announced

LG&E and KU's Team Incentive Award (TIA) is a core component of the Company's total compensation. The TIA will continue to reward employees for financial, customer satisfaction, and individual or team performance with the latter focused on important objectives such as reliability and safety.

For 2015, the primary financial measure is Net Income. The individual/team effectiveness weighting will increase from 30% to 40% and the customer satisfaction weighting remains the same. The 2015 TIA measures and weightings are noted below.

2015 TIA Measures and Weightings
45% - Net Income
40% - Individual/Team Effectiveness
15% - Customer Satisfaction

Future communications will be provided by managers to inform salaried employees of their TIA target, measures and weightings. Union and hourly TIA targets, measures and weightings will be communicated during team briefings or in bulletin board postings.

Provided below are some frequently asked questions about the TIA. If you have specific questions about your TIA, please contact your manager or the appropriate Human Resources representative.

LG&E KU
PPL companies

Employee Bulletin

Are LG&E and KU's TIA measures and weightings changing in 2015?
Yes. EBIT has been removed and the individual/team effectiveness weighting is increasing from 30% to 40%. Customer Satisfaction remains unchanged at 15%.

TIA Measure	2014 Weighting	2015 Weighting
Net Income	45%	45%
Individual/Team Effectiveness	30%	40%
Customer Satisfaction	15%	15%
Earnings Before Interest and Taxes	10%	0%

What determines Net Income?
Net Income is income after all expenses and all taxes have been deducted.

Revenue	$100,000
Less Operating Expenses	- $80,000
Operating Income (EBIT)	$20,000
Less Interest Expense	- $5,000
Less Income Tax Expense	- $5,000
Net Income	$10,000

How is Customer Satisfaction measured?
Our market research vendor calls randomly selected LG&E and KU customers and customers from each peer group company and asks them about satisfaction with their respective utility company. The scores are compiled quarterly, and those results are used to rank the utility companies.

If our overall satisfaction score is above the peer competitive range, we earn 6 points; if within the peer competitive range, we earn 3 points. Two bonus points can be earned if our overall satisfaction score is first in the absolute ranking; one point is earned if we are second in the absolute ranking. LG&E and KU's scores are communicated quarterly to employees via a *News Transmission* article.

What are Individual and Team Effectiveness measures?
Individual and team effectiveness measures are established each year to ensure we are collectively working to achieve strategic business goals. Individual goals vary by individual and by department and support respective department and line of business objectives. Team effectiveness measures are specific to each line of business and reflect key performance indicators.

2015 Electric Distribution Operations Team Goals

Measure	Measure Weighting	Targets	Range	
Safety Total Recordable Rate - (Electric Distribution Operations)	50%	2.11	1.11	3.11
Sum of customer minutes interrupted divided by the total number of customers whose service was interrupted (CAIDI)	50%	97.0	92.5	106.7

2015 Gas Distribution Operations Team Goals

Measure	Measure Weighting	Targets	Range	
Safety Total Recordable Rate - (Gas Distribution Operations)	50%	2.11	1.11	3.11
Gas Response (Response time to priority 1 calls in minutes)	50%	42 minutes	35.5	48.5

2015 Operating Services Team Goals

Measure	Measure Weighting	Targets	Ranges	
Safety Total Recordable Rate - (Combined Operations)	25.0%	0.71	0.61	0.91
Work order notification management	37.5%	99%	98	100
Preventive Maintenance Inspections	37.5%	93%	85	100

2015 Revenue Collections Team Goals

Measure	Measure Weighting	Targets	Ranges	
Safety Total Recordable Rate - (Combined Operations)	50%	0.71	0.61	0.91
Field Services work orders completed by hour	30%	3.01	2.41	3.61
Percentage of accurate meter reads completed	5%	99.9	99.8	100
Meter assets work order completion rate by number of days	15%	7-9 days	1	11

2015 IT Telecommunications Team Goals

Measure	Weighting	Target	Ranges
Safety	50%	1	0 - 3+
Average Team Competency	25%	3	0 - 5
Internal Customer Satisfaction	25%	3 - 10	0 - 19+

2015 Plant Team Goals

Ghent

Weighting	Measure	MIN - TARGET - MAX
40%	Safety - Rec Injuries (Plant)	5 - **3** - 1
15%	Cont. Budget Var - Plant (%+/-)	3.0 - **1.0** - (2.0)
15%	Cont. Budget Var - Combined (%+/-)	3.0 - **1.0** - (2.0)
30%	Availability - EFOR Plant	8.5 - **5.0** - 3.5

EWB/Tyrone Steam

Weighting	Measure	MIN - TARGET - MAX
40%	Safety - Rec Injuries (Plant)	5 - **3** - 1
15%	Cont. Budget Var - Plant (%+/-)	3.0 - **1.0** - (2.0)
15%	Cont. Budget Var - Combined (%+/-)	3.0 - **1.0** - (2.0)
30%	Availability - EFOR Plant	9.5 - **5.6** - 3.9

EWB CT's

Weighting	Measure	MIN - TARGET - MAX
40%	Safety - Rec Injuries (Plant)	5 - **3** - 1
15%	Cont. Budget Var - Plant (%+/-)	3.0 - **1.0** - (2.0)
15%	Cont. Budget Var - Combined (%+/-)	3.0 - **1.0** - (2.0)
30%	Starting Reliability	92.0 - **96.5** - 98.5

Green River

Weighting	Measure	MIN - TARGET - MAX
40%	Safety - Rec Injuries (Plant)	4 - **2** - 1
15%	Cont. Budget Var - Plant (%+/-)	3.0 - **1.0** - (2.0)
15%	Cont. Budget Var - Combined (%+/-)	3.0 - **1.0** - (2.0)
30%	Availability - EFOR Plant	11.9 - **7.0** - 4.9

Trimble County

Weighting	Measure	MIN - TARGET - MAX
40%	Safety - Rec Injuries (Plant)	5 - **3** - 1
15%	Cont. Budget Var - Plant (%+/-)	3.0 - **1.0** - (2.0)
15%	Cont. Budget Var - Combined (%+/-)	3.0 - **1.0** - (2.0)
12.5%	Availability - EFOR Plant Unit 1	6.8 - **4.0** - 2.8
12.5%	Availability - EFOR Plant Unit 2	6.5 - **3.8** - 2.7
5%	CT Starting Reliability	92.0 - **96.5** - 98.5

Mill Creek

Weighting	Measure	MIN - TARGET - MAX
40%	Safety - Rec Injuries (Plant)	5 - **3** - 1
15%	Cont. Budget Var - Plant (%+/-)	3.0 - **1.0** - (2.0)
15%	Cont. Budget Var - Combined (%+/-)	3.0 - **1.0** - (2.0)
30%	Availability - EFOR Plant	10.2- **6.0** - 4.2

Cane Run

Weighting	Measure	MIN - TARGET - MAX
40%	Safety - Rec Injuries (Plant)	4 - **2** - 1
15%	Cont. Budget Var - Plant (%+/-)	3.0 - **1.0** - (2.0)
15%	Cont. Budget Var - Combined (%+/-)	3.0 - **1.0** - (2.0)
30%	Availability - EFOR Plant Cane Run	11.9 - **7.0** - 4.9

Paddy's Run

Weighting	Measure	MIN - TARGET - MAX
40%	Safety - Rec Injuries (Plant)	4 - **2** - 1
15%	Cont. Budget Var - Plant (%+/-)	3.0 - **1.0** - (2.0)
15%	Cont. Budget Var - Combined (%+/-)	3.0 - **1.0** - (2.0)
10%	Availability - EFOR Plant Cane Run	11.9 - **7.0** - 4.9
20%	Starting Reliability - Paddy's Run	92.0 - **96.5** - 98.5

Ohio Falls

Weighting	Measure	MIN - TARGET - MAX
40%	Safety - Rec Injuries (Plant)	4 - **2** - 1
15%	Cont. Budget Var - Plant (%+/-)	3.0 - **1.0** - (2.0)
15%	Cont. Budget Var - Combined (%+/-)	3.0 - **1.0** - (2.0)
10%	Availability - EFOR Plant Cane Run	11.9 - **7.0** - 4.9
20%	Availability - EFOR Ohio Falls	33.7 - **19.8** - 13.9

LG&E And KU Energy
Labor Analysis
Forecasted Test Period Vacancy Calculation

			LG&E	KU
1.	Estimated Vacancies		44	55
2.	Total Payroll Cost of Vacancies in Plan		3,382,742	4,217,075
3.	Portion Budgeted to O&M	(67%)	2,261,002	2,818,665
4.	Estimated Overage in Overtime		(838,141)	(2,273,392)
5.	Net Payroll Impact of Vacancies and Overtime		$ 1,422,861	$ 545,272
6.	Associated Benefit Savings		762,997	701,499
7.	Net O&M Impact of Vacancies and Overtime with Benefits		$ 2,185,859	$ 1,246,771

Notes
1. Average number of vacancies 2011-2014.
2. Line 1 multiplied by average payroll cost per employee of $76,424.
3. Line 2 multiplied by the 67% O&M portion per the 2015 Business Plan.
4. See page 2.
5. Line 3 less line 4.
6. Includes 401k, payroll taxes, medical, dental, post-employment, post-retirement, and long-term disability.
7. Line 5 plus line 6.

Attorney-Client Work Product
Privileged and Confidential

AG 150 Adjusted to remove Storms and inflate to Forward Test Period.

LG&E - Total Labor

	Base Pay			Overtime Pay			Total		
	Actual	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**
2011	123,679,766	122,236,640	1,443,126	12,871,290	11,544,275	1,327,014	136,551,056	133,780,916	2,770,140
2012	128,239,705	128,101,577	138,128	13,377,256	11,593,818	1,783,438	141,616,961	139,695,396	1,921,566
2013	130,343,392	133,753,205	(3,409,813)	13,245,040	11,469,973	1,775,068	143,588,433	145,223,178	(1,634,745)
2014	133,710,750	133,952,461	(241,711)	15,165,400	10,485,269	4,680,132	148,876,150	144,437,730	4,438,421
4 Year Average	128,993,403	129,510,971	(517,568)	13,664,747	11,273,334	2,391,413	142,658,150	140,784,305	1,873,845

KU - Total Labor

	Base Pay			Overtime Pay			Total		
	Actual	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**
2011	138,963,508	147,661,316	(8,697,808)	13,767,310	9,314,619	4,452,691	152,730,818	156,975,936	(4,245,117)
2012	142,710,672	146,944,758	(4,234,087)	14,908,285	11,803,960	3,104,325	157,618,957	158,748,718	(1,129,762)
2013	146,324,352	147,742,342	(1,417,990)	14,159,640	10,696,090	3,463,550	160,483,992	158,438,432	2,045,560
2014	151,978,329	151,248,330	729,999	15,644,070	9,214,130	6,429,940	167,622,399	160,462,460	7,159,939
4 Year Average	144,994,215	148,399,187	(3,404,972)	14,619,826	10,257,200	4,362,627	159,614,041	158,656,386	957,655

LG&E - Labor Charged to Expense

	Base Pay			Overtime Pay			Total		
	Actual	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**
2011	97,243,132	99,567,669	(2,324,538)	10,009,873	9,650,423	359,450	107,253,005	109,218,092	(1,965,087)
2012	100,058,889	106,670,333	(6,611,444)	9,950,009	9,430,074	519,935	110,008,898	116,100,407	(6,091,509)
2013	98,738,531	105,817,845	(7,079,314)	9,857,742	9,762,192	95,550	108,596,273	115,580,037	(6,983,765)
2014	99,288,257	107,993,444	(8,705,187)	11,057,055	8,679,426	2,377,630	110,345,312	116,672,870	(6,327,557)
4 Year Average	98,832,202	105,012,323	(6,180,121)	10,218,670	9,380,529	838,141	109,050,872	114,392,852	(5,341,980)

KU - Labor Charged to Expense

	Base Pay			Overtime Pay			Total		
	Actual	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**	**Actual**	**Budget**	**Variance**
2011	100,232,567	112,116,166	(11,883,600)	11,158,434	8,337,669	2,820,765	111,391,001	120,453,836	(9,062,835)
2012	102,381,502	107,736,728	(5,355,226)	12,055,445	10,990,540	1,064,905	114,436,947	118,727,267	(4,290,321)
2013	105,047,758	111,778,405	(6,730,647)	11,011,206	9,863,513	1,147,693	116,058,964	121,641,919	(5,582,955)
2014	108,771,379	117,240,990	(8,469,611)	12,430,613	8,370,405	4,060,207	121,201,992	125,611,395	(4,409,404)
4 Year Average	104,108,301	112,218,072	(8,109,771)	11,663,924	9,390,532	2,273,392	115,772,226	121,608,604	(5,836,379)

Louisville Gas & Electric Company

Property Tax Capitalization Adjustments for CWIP

For the Test Year Ended June 30, 2016

$ Millions

2015 Property Tax Year (CWIP as of 12/31/14)

	Total CWIP	Real Estate	Manuf. Mach.	Other Tangible
CWIP Subject to Property Taxes Paid during 2015	$ 619.203	11.819	573.941	33.443
Remove ECR projects in CWIP	366.898		366.898	
Remaining Non-ECR CWIP Subject to Property Taxes	252.305	11.819	207.043	33.443
Percent eligible for capitalization[1]	80%	80%	80%	80%
Non-ECR CWIP Subject to Capitalization	201.844	9.455	165.635	26.754
Average Property Tax Rates		1.211%	0.150%	1.703%
2015 Property Tax Expense Based on CWIP (Exclude ECR)	$ 0.819	0.115	0.248	0.456

2016 Property Tax Year (CWIP as of 12/31/15)

	Total CWIP	Real Estate	Manuf. Mach.	Other Tangible
CWIP Subject to Property Taxes Paid during 2016	$ 366.085	6.987	339.325	19.772
Remove ECR projects in CWIP	273.364		273.364	
Remaining Non-ECR CWIP Subject to Property Taxes	92.721	6.987	65.961	19.772
Percent eligible for capitalization[1]	80%	80%	80%	80%
Non-ECR CWIP Subject to Capitalization	74.177	5.590	52.769	15.818
Average Property Tax Rates		1.233%	0.150%	1.728%
2016 Property Tax Expense Based on CWIP (Exclude ECR)	$ 0.421	0.069	0.079	0.273

Test Year Ended 06/30/16

6 Months of 2015 Property Tax Expense	$ (0.409)
6 Months of 2016 Property Tax Expense	(0.211)
Test Year Property Tax Expense Based on CWIP	$ (0.620)
Reduction to Capitalization/Rate Base:	
13 Month Average Increase to Capitalization	0.702
Rate of Return (as filed)	7.38%
NOI found Reasonable	0.052
Gross Revenue Conversion Factor (as filed)	1.608581
Adjusted Revenue Requirement	0.083
Capitalized Property Tax Expense per above	(0.620)
Net Impact to Revenue Requirement	**$ (0.537)**

Test Period	Cumulative Capital Change
Jun-15	0.409
Jul-15	0.478
Aug-15	0.546
Sep-15	0.614
Oct-15	0.682
Nov-15	0.750
Dec-15	0.819
Jan-16	0.717
Feb-16	0.752
Mar-16	0.788
Apr-16	0.823
May-16	0.858
Jun-16	0.893
13 Month Average	0.702

Calendar Year	2015	2016
Jan	0.068	0.035
Feb	0.136	0.070
Mar	0.205	0.105
Apr	0.273	0.140
May	0.341	0.176
Jun	0.409	0.211
Jul	0.478	0.246
Aug	0.546	0.281
Sep	0.614	0.316
Oct	0.682	0.351
Nov	0.750	0.386
Dec	0.819	0.421

[1] Amount eligible to be capitalized consists of projects costing more than $100,000 with a construction period of at least 12 months in duration.

Kentucky Utilities Company
Property Tax Capitalization Adjustments for CWIP
For the Test Year Ended June 30, 2016
$ Millions

2015 Property Tax Year (CWIP as of 12/31/14)

		Total CWIP	Real Estate	Manuf. Mach.	Other Tangible
CWIP Subject to Property Taxes Paid during 2015	$	892.726	2.829	846.067	43.830
Remove ECR projects in CWIP		360.316		360.316	
Remaining Non-ECR CWIP Subject to Property Taxes		532.410	2.829	485.751	43.830
Percent eligible for capitalization[1]		80%	80%	80%	80%
Non-ECR CWIP Subject to Capitalization		425.928	2.263	388.600	35.064
Average Property Tax Rates			1.085%	0.150%	1.461%
2015 Property Tax Expense Based on CWIP (Exclude ECR)	$	1.120	0.025	0.583	0.512

2016 Property Tax Year (CWIP as of 12/31/15)

		Total CWIP	Real Estate	Manuf. Mach.	Other Tangible
CWIP Subject to Property Taxes Paid during 2016	$	175.597	0.556	166.419	8.621
Remove ECR projects in CWIP		34.771		34.771	
Remaining Non-ECR CWIP Subject to Property Taxes		140.826	0.556	131.648	8.621
Percent eligible for capitalization[1]		80%	80%	80%	80%
Non-ECR CWIP Subject to Capitalization		112.661	0.445	105.319	6.897
Average Property Tax Rates			1.104%	0.150%	1.481%
2016 Property Tax Expense Based on CWIP (Exclude ECR)	$	0.265	0.005	0.158	0.102

Test Year Ended 06/30/16

6 Months of 2015 Property Tax Expense	$	(0.560)
6 Months of 2016 Property Tax Expense		(0.133)
Test Year Property Tax Expense Based on CWIP		(0.692)
KY Jurisdictional Allocation % - Forecasted Test Year		88.87%
Test Year Property Tax Expense Based on CWIP-KY Jur	$	(0.615)
Jurisdictionalized Reduction to Capitalization/Rate Base:		
13 Month Average Increase to Capitalization		1.005
KY Jurisdictional Allocation % - Forecasted Test Year		88.87%
Increase to Capitalization as of Test Period ended 06/30/16-KY Jur		0.893
Rate of Return (as filed)		7.38%
NOI found Reasonable		0.066
Gross Revenue Conversion Factor (as filed)		1.591828
Adjusted Revenue Requirement		0.105
Capitalized Property Tax Expense per above		(0.615)
Net Impact to Revenue Requirement	**$**	**(0.510)**

Test Period	Cumulative Capital Change
Jun-15	0.560
Jul-15	0.653
Aug-15	0.746
Sep-15	0.840
Oct-15	0.933
Nov-15	1.026
Dec-15	1.120
Jan-16	1.142
Feb-16	1.164
Mar-16	1.186
Apr-16	1.208
May-16	1.230
Jun-16	1.252
13 Month Average	1.005

Calendar Year	2015	2016
Jan	0.093	0.022
Feb	0.187	0.044
Mar	0.280	0.066
Apr	0.373	0.088
May	0.467	0.110
Jun	0.560	0.133
Jul	0.653	0.155
Aug	0.746	0.177
Sep	0.840	0.199
Oct	0.933	0.221
Nov	1.026	0.243
Dec	1.120	0.265

[1] Amount eligible to be capitalized consists of projects costing more than $100,000 with a construction period of at least 12 months in duration.

CASE NOS. 2014-00371 AND 2014-00372 **REBUTTAL EXHIBIT KWB-6**

RATE CASE REVENUES **PAGE 1 OF 1**

($ Millions)

COMPANY	KU	LGE-E	LGE-G	TOTAL
AS FILED-NOTICE	153.4	30.3	14.3	198.0
CORRECTIONS (PSC 1-59 SUPPLEMENTAL)	1.9	(2.3)	-	(0.4)
BONUS DEPRECIATION (AG 1-27 KU, AG 1-26 LGE)	3.1	(3.4)	(1.9)	(2.2)
COMPANY NET	158.4	24.6	12.4	195.4

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2014-00371**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

REBUTTAL TESTIMONY OF
PAUL W. THOMPSON
CHIEF OPERATING OFFICER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Dated: April 14, 2015

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

A. My name is Paul W. Thompson. I am the Chief Operating Officer 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 respond to certain arguments presented in the testimony of Lane Kollen on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC") and Frank Radigan on behalf of the Attorney General ("AG"). Specifically, I will address questions relating to the Companies' proposed headcount, the costs to dismantle unsafe facilities at the Paddy's Run Generating Station, and the reasonableness of forecasted gas maintenance expenses.

<u>EMPLOYEE HEADCOUNT</u>

Q. How do the Companies determine when additional headcount is needed?

A. We review workforce requirements in a systematic process each year. This process starts each year by having members of our Human Resources ("HR") Department meet with their colleagues within each business area of the Companies for a discussion as to incremental hiring or reductions on a year-over-year basis. Each business area will suggest headcount position changes over the next five years based on its needs. After much discussion, these requests are normally altered to account for Company-wide needs and budgetary constraints. Eventually, HR and the person in charge of each functional area submit a plan to the Companies' senior executives for approval. Virtually every new position must be justified by a detailed demonstration of the specific need for the position, the risks associated with not filling the position, the hiring timeframe, and other important information, such as salary and benefits and allocation of costs between capital and operations and maintenance ("O&M"). This process is further described in the Companies' *Workforce Plan* produced by KU in response to PSC 2-17 and by LG&E in response to PSC 2-24.

Q. What are the drivers of the additional headcount proposed by the Companies?

A. The drivers vary by line of business. The Companies' HR Department classified each of the new headcount positions into one of five primary categories: (1) capital projects, (2) core skill building/knowledge retention and transfer, (3) corporate reorganization, (4) customer service commitments, and (5) regulatory compliance. While all positions have been placed into one category or another, in reality, almost every incremental position is necessary for multiple reasons and fits within more than one category. For example, while an Electric Distribution line technician may be classified as "core skill building/knowledge retention and transfer," the technician is being hired to assist with capital projects, customer service commitments, and regulatory compliance as well. Therefore, the costs for many headcount positions are charged between capital and O&M expense, with some positions, such as engineering positions, being recovered entirely or partially as a capital expenditure due to their being tied to a specific project. When such labor costs are charged to projects recovered through the environmental surcharge or gas line replacement mechanism, the costs are not recovered through base rates. Below, my testimony details the operational need for additional headcount within each operational line of business.

Q. Does reliance on contractors tell part of the story?

A. Yes, for multiple reasons. Contractors are an important part of the Companies' overall workforce management strategy. In determining whether to increase the Companies' headcount, the Companies, as a matter of course, assess whether a given task or duty should be performed by an employee versus using an outside contractor on the basis of cost and other considerations.

The record shows a substantial number of the headcount increase involves a corresponding contractor offset. In fact, 89 of the 265 operational headcount positions within my supervision involve a corresponding contractor offset. The specific positions that include a contractor offset are shown on Rebuttal Testimony Exhibit PWT-1. Much like the Companies' current employees, many of the outside contractors have a workforce that is now reaching retirement age. Based upon these assessments, the Companies have determined that it is now necessary and appropriate to migrate some of these positions back in-house to protect and advance the critical skills needed to safely and reliably serve our customers in a cost-effective manner.

Q. Did the Companies engage an independent consultant to review their staffing levels?

A. Yes. The Companies have prudently managed their hiring practices in the past and will continue to do so in the future. The Towers Watson study prepared by David Wathen shows the Companies are lean and will continue to be lean even after the incremental positions indicated on Rebuttal Testimony Exhibit PWT-1 are added. Suggestions that the Companies have been engaged in a "hiring frenzy" are simply wrong.

Q. Are there any other general considerations relating to headcount?

A. Yes, it always starts with safety, safety, safety. The safety of our customers, employees, and business partners is a foremost consideration. We deal with electricity and natural gas, two inherently dangerous commodities, albeit extremely important and useful commodities. In our industry, system failure, lack of sufficient training, and short-staffing can lead to catastrophic results. Certain positions are so critical or require so much training that the Companies cannot wish a long-term employee a happy retirement on Friday and welcome a new employee on Monday. For example, the Companies cannot justifiably hire a brand-new line technician and immediately send the technician off to work to take actions that will impact the technician's and our customers' safety. The Companies' employee work crews are not staffed with multiple levels of supervisors. Electric and gas distribution crews can consist of one-to-three employees who are expected to diagnose and resolve problems without on-site supervision, direction, or guidance. While the Companies strive to balance low-cost energy to ratepayers against operational expenses, the safety of our customers, employees, and business partners always comes first.

The False Premises Supporting KIUC's Headcount Argument

Q. Briefly summarize Mr. Kollen's testimony.

A. Mr. Kollen asks the Commission to disallow the labor expense associated with 200 of 293 positions the Companies have classified as "core skill building/knowledge retention and transfer." Mr. Kollen supports his recommendation by arguing the title, "almost by definition," shows these employees are duplicative.[1] This is incorrect.

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

A. No. Employees being hired due to "core skill building/knowledge retention and transfer" are needed to ensure the Companies have employees capable of completing critical work ranging from inspecting boiler tubes on generating units to inspecting high-voltage

[1] *See* Direct Testimony of Lane Kollen at 17.

transmission line construction. Below, I explain in further detail the reasons why the Companies need additional headcount by operational line of business.

Q. Are there flaws in Mr. Kollen's testimony?

Mr. Kollen's approach begins with a false premise. According to Mr. Kollen, headcount increases are caused solely by load growth, and "mature" utilities with a flat load growth do not require additional employees.[2] This argument is untenable, primarily because it necessarily makes the following false assumptions:

- Regulatory requirements are static. In reality, the Companies face numerous new regulatory requirements. Moreover, existing regulatory requirements continue to evolve. As industry events occur, what once constituted compliance is no longer deemed sufficient.
- Customer expectations remain the same. In reality, customers today expect the Companies to play a vital role in the communities we serve. Customers also expect a level of access not previously possible. From outage maps to bill pay, customers want and deserve the ability to get information when they want it, in the method they want it.
- Workforce is stable. In reality, workforce turnover happens. Past staffing practices were efficient and benefited our customers; however, a new, likewise appropriate and efficient, approach is now needed to continue to safely and reliably serve our customers.

[2] *See* Direct Testimony of Lane Kollen at 13.

- Infrastructure requirements are static. In reality, certain existing infrastructure is aging and needs increased maintenance or replacement, irrespective of the load needed to serve additional customers.
- New equipment is not required. In reality, environmental, reliability, safety, and other regulations require additional facilities and, correspondingly, incremental staffing to operate the facilities.

In sum, Mr. Kollen's argument disregards the increased operating complexity and changes in today's utility industry.

Mr. Kollen also asserts the Companies have failed to hire appropriately over the years. Mr. Kollen argues that the Companies plan to hire employees "outside of and in addition to the normal employee replenishment process."[3] Mr. Kollen does not account for the Companies' actual experience, which is to hire employees based on needs and qualifications and empower these employees to independently perform their work without multiple layers of hands-on supervision and oversight. The Companies have been operating lean for many years by using, for example, one-to-three member operating crews in the electric and gas distribution areas to perform their assignments without on-site supervision or direction.

Mr. Kollen's approach is also inconsistent. On one hand, Mr. Kollen testifies the Companies should have been prepared for impending retirements, which would have required a higher employee headcount and costs in past years; on the other hand, Mr. Kollen testifies the Companies should not be allowed to recover for hiring employees now to address the Companies' aging workforce as demonstrated on the chart labeled "LKE

[3] *See* Direct Testimony of Lane Kollen at 17.

Age Demographics" on page 7 of the Companies' *Workforce Plan*. The chart shows that a large percentage of the Companies' workforce is age 50 and above, while a smaller percentage is age 40 and lower. KIUC cannot have it both ways. The workforce has been lean, and will continue to be lean, but the time to address the impending retirements is now.

Generation Headcount

Q. Will the Companies' Generation headcount increase from April 1, 2012, through June 30, 2016?

A. Yes. The Companies' Generation headcount will increase by a net of 50 positions during this timeframe. These positions do not involve a corresponding contractor offset. For purposes of these cases, the Companies have defined "Generation" to include the traditional Power Production function, Project Engineering, Generation Services, and Energy Supply and Analysis.

Q. What are the drivers for the Companies' increased Generation headcount?

A. Broadly speaking, the need for increased headcount is driven by three interrelated factors: (1) new machinery and equipment, (2) regulatory requirements, and (3) process improvements. For context, from 2011 through the end of the forecasted test period, the Companies' Project Engineering group will have overseen nearly $2.5 billion in capital expenditures related to environmental compliance, approximately $600 million in capital expenditures related to Cane Run Unit 7 ("CR7"), approximately $600 million in coal combustion residual ("CCR") long-term storage projects at the Ghent, Brown, Cane Run, and Trimble County Generating Stations, and numerous smaller projects and improvements.

Q. Please describe these drivers.

A. For new machinery and equipment, the Companies' generating fleet and associated facilities have undergone and continue to undergo significant change. Just a few years ago, Trimble County Unit 2 ("TC2") achieved commercial operation. In the very near future, CR7 will achieve commercial operation. Conversely, the Companies will soon be retiring the coal-fired generating units at the Cane Run Generating Station and Green River Generating Station. Generating power in the United States looks much different today than just a handful of years ago.

Today, it takes more equipment, processes, and headcount to generate the same amount of energy, largely because of regulatory requirements. The Companies must comply with regulations and rules ranging from the National Ambient Air Quality Standards, Cross-State Air Pollution Rule, CCR rules, and Mercury and Air Toxics Standards to the many mandatory reliability standards from the Federal Energy Regulatory Commission ("FERC") and the North American Electric Reliability Corporation ("NERC"). To comply with these regulatory schemes, the Companies have undertaken numerous Commission-approved environmental compliance projects while also constructing their first natural gas combined-cycle generating unit. As an example, the required addition of CCR processing equipment at Ghent is comparable to a new industrial manufacturing facility. New equipment includes nearly 300 motors, 55 pumps, 30 blowers and compressors, 1.5 miles of conveyor, and 36,000 feet of piping, all of which requires manpower to provide uninterrupted operability and not impact the station's ability to generate electricity. As well, the Companies have responded with processes to comply with and provide auditable evidence for FERC reliability standards.

This new machinery and equipment and changed regulatory scheme has, in some instances, resulted in process improvements. For example, new monitoring software at generating units allows the Companies to review real-time performance data. As I explained in my direct testimony, this results in increased productivity and efficiency as it relates to predictive maintenance and O&M cost. The Companies have also attempted to standardize training and other processes across the generating fleet. These improvements do, however, require additional employees to develop and administer them.

Q. Can you give specific examples of new positions within Generation and the need for the positions?

A. Yes. The Companies have always been committed to staffing TC2 at as lean of a level as commercially reasonable since it became operational in early 2011. Mr. Kollen fails to account for this fact, stating that because TC2 became operational in January 2011, "the additional employees required to operate and maintain the unit were hired in 2010."[4] Mr. Kollen's "opinion" has no basis in fact. The original TC2 operational staff was conservatively sized with the known sensitivity that additional staff would be added as unit operating experience was gained and unit O&M dictated. Since TC2 became commercially operational, the Companies have determined a need to add 10 total positions that are attributed directly to TC2 operations, including positions for engineering, hourly technicians, operations, and maintenance-management support.

Another example is the addition of one operator per shift at the Mill Creek, Ghent, and Trimble County Generating Stations, which equates to 4 positions per plant. These plants operate—and therefore, require staffing—7-days per week, 24-hours per day, which

[4] *See* KIUC Response to PSC First Request of Information, No. 2.

requires 4 rotating workgroups to achieve. Adding operators helps to manage overtime and allows fulfillment of training requirements.

Additionally, approximately 8 new engineering positions have been, or will be, added to specific plants to oversee new landfill operations and to develop project scope requirements for the construction and operation of additional equipment required to meet the forthcoming effluent limitation guidelines.

The Companies have also hired a consumer behavior analyst, which is a reflection of the changing industry. Today, many customers place a greater focus on energy efficiency and demand conservation. The consumer behavior analyst studies these trends and patterns to develop a greater understanding of how they will impact future resource needs, rate design, and demand-side management programs.

Transmission Headcount

Q. Will the Companies' Transmission headcount increase from April 1, 2012, through June 30, 2016?

A. Yes. The Companies' Transmission department headcount will increase a net of 19 positions during this timeframe. Of these 19 positions, 8 involve a corresponding contractor offset.

Q. What are the drivers for the increased Transmission headcount?

A. The drivers range from operating new software programs that assist with asset management and predictive maintenance to ensuring compliance with mandatory NERC reliability standards to design and construction of capital projects. The Transmission department has a wide range of complex responsibilities and significant and direct responsibility for assuring adherence to certain mandatory NERC Critical Infrastructure Protection ("CIP") standards and operations and planning reliability standards.

Q. Please give examples of the need for Transmission to increase its headcount.

A. About three years ago, Transmission began using software known as Cascade to assist with ongoing equipment maintenance and managing facility ratings and asset technical data. Previously, the Companies had multiple databases and paper records to fulfill these functions. Cascade streamlines this process by providing real time, up-to-date asset data and information about past maintenance and upcoming maintenance needs. This information is readily available to technical staff in multiple locations, including by field technicians using mobile laptops. The process is more automated, secure, reliable, accurate, and is constantly available to those who need it in daily operations. Cascade also creates an audit trail that is critical for providing evidence to SERC Reliability Corporation auditors and to meet mandatory NERC reliability standards, such as Standard PRC-005. However, this improved asset management process requires human resources to maintain and ensure data integrity and analysis, so additional headcount was added.

Transmission has also added planning engineers. These individuals perform highly technical analyses and planning for the transmission system to ensure reliable operation of the electrical grid in real time and for the long term. Planning engineers also assist the Companies with complying with NERC's mandatory Transmission Planning standards, CIP standards, and development of the Companies' annual Transmission Expansion Plan.

As a final example, the Companies have hired two system control engineers to assist with regulatory compliance. One of these engineers primarily supports compliance with mandatory NERC operations and planning standards within the control center. The second engineer supports training program development and delivery required for system operators within the department, including maintenance and training on the Companies' operations simulator as required by regulatory standards.

Q. Are there other factors involved in the increased headcount?

A. Yes. The Companies' capital investment in the transmission system is anticipated to have increased by a factor of nearly five from 2005 through 2019, going from about $22 million to about $100 million in capital spend from 2005 through 2019, respectively. This growth is driven by needed upgrades and modifications to the transmission grid to reliably support the changing generation-resource mix, new and changing load-delivery points, and to meet NERC reliability requirements. Also, because the transmission grid is interconnected with many other utilities, the Companies must consider both their own load and generation changes and those of neighboring utilities when conducting transmission analyses. Consider, for example, the recent construction of the Outlet Shoppes of the Bluegrass in Simpsonville, Kentucky. A neighboring utility constructed a new distribution substation to help serve this load and the forecasted load at this substation will require the Companies' to upgrade certain facilities.

Increased capital investment in Transmission requires headcount to plan, engineer, and implement the associated construction. Additionally, changes to generation resources and loads require Transmission planning engineers to analyze whether anticipated power flows can be served reliably by the existing system or if upgrades are required.

Furthermore, Transmission is responsible for over 900 unique and mandatory NERC compliance requirements on an ongoing basis that may be audited and reviewed at any time by our regulators. The utility world we live in today is far more complex than what it was a few years ago, and it continues to change at a rapid pace. This world requires more headcount, and specifically more internal headcount, to ensure a reliable, interconnected electric transmission grid.

Electric Distribution Headcount

Q. Will the Companies' Electric Distribution headcount increase from April 1, 2012, through June 30, 2016?

A. Yes. The Companies' Electric Distribution headcount will increase a net of 53 positions during this timeframe. Of these 53 positions, 41 involve a corresponding contractor offset.

Q. What are the reasons for this headcount increase?

A. First, the Companies need to mitigate the increasing risk of using contractors for skilled utility technician positions. This risk is caused by an increasingly competitive and constrained job market for skilled contractor labor. Second, the Companies need to address the upcoming retirement wave of skilled contractors. The best way to meet these challenges is to replace skilled contractors with skilled employees.

Q. Please explain these headcount drivers.

A. The Companies' business partners have indicated the market for experienced utility technicians in the electric industry is becoming increasingly competitive. Some industry contractors have advised of regional labor-cost increases of 25% to 30% due to labor demands associated with growing industry investments in reliability, aging infrastructure, distribution automation, third-party telecommunications "make-ready" work, and mandatory NERC reliability standards. Contractors have also warned of increased labor and knowledge-retention issues as their employees are jumping from company to company to obtain promotions, higher wages, enhanced benefits, or more stable positions.

Prime examples of the need to bring certain positions in-house include line technicians, network technicians, and substation technicians. These technicians hold critical positions that require highly specialized technical skills, and more importantly, unique system and equipment knowledge. These technicians require between five and seven years of experience to reach full proficiency and be fully effective as part of small crews. The viable market for contractors with the required system and equipment knowledge and experience is declining, which means finding qualified utility technicians in the electric industry is not consistently and readily possible in the contractor market. To the extent such resources are available, the Companies are concerned with the lack of a robust market to obtain competitively priced contractor services. The Companies are responding to this changing industry dynamic by increasing the number of certain positions, including these technician positions, staffed in-house.

On a related point, much of the skilled contractor workforce is approaching retirement. This changing contractor workforce caused the Companies to reassess the ratio of contractors to employees. Ultimately, the Companies determined that employees should fill certain positions due to the changes in the contractor marketplace mentioned above. This strategy reduces turnover risks, protects training investments, and provides for the necessary knowledge retention of the Companies' system and equipment. Again, using line technicians as an example, more than two-thirds of the line technicians working on the LG&E system have been contractors for many years, while about one-fourth of the line technicians on the KU system have been contractors. These individuals are now retiring or approaching retirement age, and the knowledge they possess of the LG&E system cannot be replaced by a new contractor. The ability to work in independent, small crews without continuous on-site supervision and management is essential to addressing service issues in a timely, safe, and cost-effective manner. Schools that train line technicians provide only about ten weeks of training. Placing a new line technician in the field alone is more than a risky proposition; it is a potentially unsafe proposition.

Q. Can you provide other examples of the need for additional headcount?

A. Yes. Field coordinators are a good example. Field coordinators supervise, lead, train, and support Electric Distribution workers in the field. Field coordinators oversee newly hired line technicians and provide them with training. This position also serves as a regular pipeline for development as a future team leader. Each of the three field coordinators the Companies plan to hire will correspond to a contractor offset.

Perhaps most importantly, in responses to large, challenging restoration events like the Hurricane Ike Windstorm and 2009 Kentucky Ice Storm, the Companies rely heavily on experienced employees, such as field coordinators and line technicians, to oversee off-system mutual aid resources providing assistance (i.e., to serve as "Bird Dogs"). Their knowledge of the Companies' systems, equipment, and processes are needed and essential to providing direction to mutual aid resources and to oversee restoration and repair activities. Our customers expect, and should expect, rapid restoration of power following an outage.

<u>LG&E Gas Distribution Headcount</u>

Q. Will LG&E's Gas Distribution headcount increase from April 1, 2012, through June 30, 2016?

A. Yes. LG&E's Gas Distribution headcount will increase a net of 42 positions during this timeframe. Of these 42 positions, 7 involve a corresponding contractor offset.

Q. Do any intervenor witnesses discuss LG&E's Gas Distribution headcount?

A. Not specifically. Mr. Kollen intentionally avoids any discussion of LG&E's Gas Distribution headcount by stating the increase in headcount is 293 based upon data requests from KIUC that specifically excluded LG&E Gas. I assume that Mr. Radigan wants the general principles of his testimony to be applied to LG&E Gas although he fails to state as much or to identify a single LG&E Gas position as being unneeded. Instead, he provides an inherently flawed schedule to support a disallowance.

Q. What is driving the need for increased headcount in LG&E's Gas Distribution business?

A. The need for additional LG&E Gas headcount may be divided into five categories: (1) work related to existing Gas Distribution programs, (2) targeted contractor replacements, (3) expansion of regulatory based activities, (4) targeted hires in anticipation of key retirements, and (5) new work related to increased capital or operational needs.

Q. Please describe these five categories.

A. First, for work related to existing Gas Distribution programs, LG&E has continued work on Commission-approved construction and capital projects and will continue to do so in the future. For example, the riser replacement program began in April 2013 to replace or inspect every riser on the LG&E gas system. Through March 19, 2015, LG&E has replaced 84,482 risers and inspected another 35,504 risers for a total system impact of 119,986 risers, which covers 40.3% of the LG&E gas system. This program, approved by the Commission and included within the unanimous settlement agreement signed by all parties in the last rate case, requires additional headcount. The same is true of LG&E's ongoing main replacement program.

Second, LG&E Gas is engaging in targeted contractor replacements for several positions, most of which are gas regulatory associates. Combined with existing work needs, the level of work within Gas Distribution now justifies bringing certain former contractor positions in-house. Gas regulatory associates participate in a variety of tasks, including numerous compliance-related tasks. These tasks include supporting leak surveys, curb valve inspections, and atmospheric corrosion inspections; providing public education; identifying upcoming compliance deadlines; issuing work to field personnel; and processing completed field work, all to assist LG&E in demonstrating compliance with regulations. One such regulation is the final rule establishing distribution integrity management requirements, published in 2009 by the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration. The rule was effective in early 2010 and the industry was given until the summer of 2011 to comply. The final rule requires companies like LG&E to establish and implement a distribution integrity management plan. The rule also established a significant number of new data requirements, which led to more work. A similar rule is in place with respect to gas transmission.

Third, LG&E Gas is required to comply with an expanding universe of regulatory requirements. Sometimes, such as with the integrity management requirements listed above, this compliance is related to new regulations. Other times, the compliance is due to new or enhanced focus on existing regulatory requirements. For example, following the gas pipeline incident in San Bruno, California, in 2010, increased emphasis has been placed on pipeline inspections. Therefore, the Companies need additional engineers, analysts, and technicians to comply with federal pipeline safety regulations, such as to check for pipeline corrosion pursuant to Section 192, Title 49 of the Code of Federal Regulations. The Companies also plan to hire a training specialist to meet the enhanced regulatory scheme.

Fourth, LG&E is making targeted hires in anticipation of key retirements. As I mentioned above, Mr. Kollen takes the Companies to task for not having a deep enough "bench." Mr. Kollen even states the Companies are hiring "duplicative" employees.[5] In reality, now is the prudent time to begin staffing the next wave. The Companies' *Workforce Plan* describes the Companies' aging workforce and the level of upcoming retirements the Companies face. The Companies must be prepared for future needs. Impending retirements likely mean that some individuals will be promoted. Promotions have a ripple effect. For example, a member of the LG&E gas trouble crew—the first responders to gas emergencies—may be promoted. The gas trouble crew position must then be filled, and is normally filled by a distribution mechanic. At present, LG&E Gas does not have enough distribution mechanics with adequate experience to ensure that a crucial position, such as the first responders to a gas emergency, is filled by a trained, knowledgeable individual once the upcoming retirements occur while simultaneously retaining an adequately trained distribution mechanic workforce. Safety requires that we act now.

Finally, LG&E Gas must increase headcount to meet the work required by increased capital and operational needs. For example, LG&E Gas recently installed additional gas compression equipment at LG&E's Magnolia and Center storage fields in an effort to continue to optimize the utilization of its gas storage fields. The project included the installation of a natural gas fueled compressor unit at Magnolia and the installation of two natural gas fueled compressor units at Center. This new compression equipment augments the existing 15 gas compressors at Muldraugh and Magnolia, but also

[5] *See* Direct Testimony of Lane Kollen at 17.

requires additional employees. As another example, LG&E Gas needs additional Instrumentation, Measurement & Electronics Technicians. The Magnolia and Muldraugh Gas Storage fields currently have only one such position. These individuals deal with more equipment than ever before, cannot take time off during key winter-month periods, and—as a testament to how hard our employees work—even sleep at their respective jobsites during certain extremely cold spells for extended periods of time, such as the four consecutive days and nights these individuals spent at their jobsites this past winter to ensure customers received the gas they needed to heat their homes and businesses.

Customer Service Headcount

Q. Will the Companies' Customer Service headcount increase from April 1, 2012, through June 30, 2016?

A. Yes. The Companies' Customer Service headcount will increase a net of 93 positions during this timeframe. Of these 93 positions, 33 involve a corresponding contractor offset.[6]

Q. As an initial matter, please explain what roles the Customer Service group encompasses.

A. The Companies' Customer Service group does more than just interact with customers on a routine basis through phone calls and email communications. Customer Service employees manage real estate and right-of-way operations, state and national economic-development

[6] The 93 net positions created in Customer Service involve 33 contractor offsets. Of these 33 contractor offsets, 28 are for KU and amount to $993,195 in contractor-offset expense, while 5 are for LG&E and amount to $306,422 in contractor-offset expense. The Companies' data responses previously listed 24 contractor offsets, 20 of which involved $764,672 in contractor-offset expense for KU, and 4 of which involved $260,813 in contractor-offset expense for LG&E. The positions with a corresponding contractor offset are shown on Rebuttal Testimony Exhibit PWT-1. For KU, this update applies to PSC 2-22, PSC 3-7, AG 1-24, AG 1-154, AG 2-24, KIUC 1-10, KIUC 2-18, KIUC 2-20, and Kroger 1-12. For LG&E, this update applies to PSC 2-31, PSC 3-12, AG 1-23, AG 1-154, AG 2-24, KIUC 1-10, KIUC 2-18, KIUC 2-20, and Kroger 1-13.

support, facilities management, field services, electric and gas meter operations inclusive of meter reading, energy efficiency operations, tariff application, and customer billing.

Q. What are the drivers of this need for increased Customer Service headcount?

A. As obvious as it sounds, the main driver is to meet increased customer expectations, which are the norm nationwide across all industries. The Companies make every effort to provide their customers with a positive experience. Doing so requires the customer's bill to be correct, the customer to receive timely and adequate information, and the customer to be treated in a positive manner.

Also, the Companies' Customer Service functions were the subject of a Focused Management and Operations Audit that was published in September 2011.[7] The Companies implemented a variety of recommendations following the audit, and the Companies' customer-service metrics show these actions have had a positive impact. The table on Rebuttal Testimony Exhibit PWT-2 highlights some high-level customer-service metrics comparing 2009 to 2014. Of specific note is our increased ability to answer customer calls within 30 seconds and the decline in our call-abandonment rate. These actions and others have allowed us to increase customer satisfaction across this same period as reflected on Rebuttal Testimony Exhibit PWT-2.

Q. Please provide specific examples of the need for increased headcount.

A. Twenty-six of the 93 incremental positions are for call center representatives. During the audit, the Companies and the Auditor discussed setting a goal of answering 80% of calls to live agents within 30 seconds. As the audit action plan recognized, "[c]osts to implement

[7] The Liberty Consulting Group, *Focused Management and Operations Audit of Kentucky Utilities Company and Louisville Gas and Electric Company* (Sept. 12, 2011).

this recommendation will be significant" because the only way to achieve the goal was to hire more call center representatives.[8] The Companies are now meeting their goal to answer at least 80% of calls within 30 seconds, but only because additional employees were hired both before and after April 1, 2012.

The Companies also have hired customer service support personnel including customer care coaches (2), business analysts (2), quality assurance staff (2), and a customer relations associate whose primary functions are to support customer-facing personnel with training and assistance for complex customer issues. The customer relations associate investigates and responds to customer inquiries and complaints and trains low-income groups on how to apply customer-assistance payments online. The Companies also have added 4 billing analysis associates to evaluate billing exceptions, manage complex billing issues, and ensure overall accuracy / integrity in customer billing. Following these staffing decisions, customer complaints have been cut approximately in half year over year.

In the metering area, 6 individuals were hired to address the continued deployment of ARM electric meters and ERT equipped gas meters. Additionally, these individuals provide the foundational support for the deployment of advanced metering operations consistent with the Companies' approved Advanced Meter Opt-In program.

Lastly, the Customer Service group is now subject to CIP requirements and has been forced to add four new positions to comply with CIP. These positions include a CIP Coordinator, CIP associates (2), and a security technical assistant. CIP now requires the Companies' Customer Service facilities be secure through fencing, cameras, key card

[8] Management Audit Action Plan at 3,
available at http://psc.ky.gov/agencies/psc/M_Audit/LGE_KU_CS_Audit_Action_Plan_Final.pdf.

access, and non-penetrable, “6 wall” boundary protection that were not previously required.

Q. Mr. Kollen takes specific exception to KU’s decision to transfer 11 employees from the Green River Generating Station into meter reading following the retirement of the Green River units. Why is KU transferring these individuals to meter reading?

A. First, there is a need for these positions and second, the Companies have an obligation to the United Steel Workers to retain these workers pursuant to labor agreements. Moreover, each of these positions corresponds with a contractor offset. The eleven employees are not simply being added to the Metering Department without work to perform as the KIUC argument suggests. They will replace contactors who are currently reading meters.

Safety Headcount

Q. Will the Companies’ Safety department headcount increase from April 1, 2012, through June 30, 2016?

A. Yes. The Companies’ Safety department headcount will increase a net of 8 positions during this timeframe. None of these 8 positions involve a corresponding contractor offset.

Q. What are the drivers for this increased headcount in Safety?

A. The Companies reorganized their Safety and Training departments in 2013. This reorganization resulted in 5 positions being transferred into Safety that were previously in other departments. The 3 remaining net positions are for 2 training consultants and 1 safety metrics analyst. The Companies need these positions to continue achieving their positive overall safety experience and to continue stressing their “No Compromise” approach to safety. The Companies recognize that increased training, due in part to newer employees and more complex operations, is critical to operational excellence in a safe manner.

Q. In summary, what do you recommend with respect to KIUC Witness Kollen’s claims?

A. KIUC's claims should be rejected. There is no basis for disallowing recovery of costs associated with needed employees just because Mr. Kollen does not like a heading used to classify a new position. Mr. Kollen's headcount arguments are unsound, inconsistent, and fail to account for real-world variables. The Companies have operated with a lean workforce for years, much to the benefit of ratepayers. The Companies will continue to manage the size of the workforce to maintain their mission to deliver safe and reliable energy at cost-effective rates. These necessary changes were not brought about by the Companies, but by the Companies responding to the increased operating complexity of today's utility industry.

<u>The AG's Headcount Recommendation Is Unsupported and Flawed</u>

Q. Please summarize the testimony of AG Witness Frank Radigan concerning the estimated headcount expenses.

A. Despite these cases involving forecasted test periods, and without any meaningful evidence to support his recommendation, Mr. Radigan proposes the Companies be limited to the headcount that existed on December 31, 2014. Mr. Radigan is inherently suspicious of any forecasted test period, even stating that the "potential danger" of such cases is that they rely on forecasts.[9] Mr. Radigan speculates that the Companies could inflate forecasted headcount to receive additional revenue, but then not hire the individuals. Mr. Radigan's claims have no support.

Q. Do you agree with Mr. Radigan's testimony that the Companies should not be allowed to recover the expense for employees they plan to hire by the end of the forecasted test year but have not hired as of December 31, 2014?

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[9] *See* Direct Testimony of Frank Radigan at 17 (KU Case No. 2014-00371); Direct Testimony of Frank Radigan at 19 (LG&E Case No. 2014-00372).

A. Not at all. The Companies have put forth their employment forecasts and their reasons for needing an increased headcount. Mr. Radigan's unsupported opinion fails to provide any legitimate reason for disallowing the planned additions. Rather, Mr. Radigan relies upon the weight of his own opinion and on a recurring theme of forecasted data not being as known and measurable as historic data. Mr. Radigan also states the Companies may not actually hire these individuals. Mr. Radigan ignores the fact that the Companies have included these headcount additions in their approved forecasts, which were provided in good faith as the actual forecast prepared for use by management. The Companies plan to fill these positions and, in fact, have filled many of them subsequent to December 31, 2014. This is reflected in my Rebuttal Testimony Exhibit PWT-3.

Rebuttal Testimony Exhibit PWT-3 is a spreadsheet that updates the Companies' responses to AG Data Request 1-154. When the Companies initially responded to AG Data Request 1-154, a net 92 positions that were forecasted to be added during the base year (ending February 28, 2015) and the test year (ending June 30, 2016) had not yet been added. These 92 net positions were comprised of 152 forecasted new hires, offset by 60 forecasted retirements or transfers.[10] As of March 31, 2015, 72 positions have been filled and 3 retirements have occurred for a net headcount increase of 69 positions. Therefore, the 152 forecasted new hires had been reduced by 69 for a total of 83 remaining hires, 40 of which had a pending start date or active posting on March 31, 2015. The 83 remaining hires will be offset by 60 forecasted retirements or transfers. In other words, as of March 31, 2015, the Companies had only 23 net positions remaining to hire. Mr. Radigan's unfounded

[10] The yet-to-occur retirement of the Cane Run and Green River Generating Stations account for 51 of the 60 forecasted retirements or transfers.

assertion that the Companies may forecast headcount growth only to not hire and "keep the money" is incorrect and refuted by this evidence.

Q. Please comment on the need for the remaining positions that are not yet filled at this time.

A. These positions are listed in more detail on Rebuttal Testimony Exhibit PWT-3. Many of the not-yet-filled positions, 28 to be exact, are in Customer Service. Of these, 11 positions are for the current Green River Generating Station employees who will be transferred to meter reading within Customer Service pursuant to need and labor agreements. The other positions are for customer representatives, demand-side management ("DSM") programs, right-of-way agents, facility operations, and a call center business analyst. The remaining positions are needed throughout the Companies' operational lines of business and range from a gas analyst who will have primary responsibility for metrics, benchmarking, and communications within Gas Distribution to a material handling leader in generation who will oversee and lead contractor crews who do the bulk of material handling.

Q. Has Mr. Radigan made any errors in his proposed recommendation?

A. Yes. Mr. Radigan's proposed labor-expense reductions are overstated and unsupported, apparently because Mr. Radigan uses an understated contractor-offset amount for the Companies' Electric Distribution, Transmission, and Customer Service areas while failing to include any contractor-offset amount for LG&E's Gas Distribution operations. Mr. Radigan's use of incorrect contractor-offset amounts causes the remainder of his work to be incorrect. For example, in response to the Companies' Request of Information No. 2, Mr. Radigan produced an Excel spreadsheet titled "Labor Book 4-1-15.xlsx." In Columns E and F for Cost, the Labor Book includes dollar amounts found on the Companies' responses to subpart (b) of Kroger Data Requests 1-11, 1-12, 1-13, 1-14, and 1-15. The amounts listed correspond with the data responses. The same cannot be said for the contractor offset amounts found in columns G and H of Mr. Radigan's spreadsheet. The same Kroger data responses listed above include dollar amounts for offsetting contractor expense and net payroll increase resulting from additional headcount.

Mr. Radigan ignores these numbers and creates his own offset amounts, amounts which the Companies cannot tie and which appear to be unsupported. Mr. Radigan's incorrect calculation, or utter disregard, of the correct contractor-offset amounts results in the balance of his calculations being overstated and his adjustments inflated. As but one example, the correct net payroll increase for Electric Distribution headcount over the relevant time is $24,049 for KU, while LG&E has a net decrease of $393,136.[11] Mr. Radigan states that KU has a net increase of $618,707 and that LG&E has a net increase of $2,413,396,[12] which is a total difference of approximately $3.4 million.

Mr. Radigan's "Labor Book" also misstates LG&E's Gas Distribution hires as of December 31, 2014, which results in the "% Allowed" and "AG Recommended" columns of his spreadsheet being incorrect. As LG&E's response to Kroger Data Request 1-16 states, LG&E Gas had filled 26 of 42 net positions as of December 31, 2014. Mr. Radigan's "Labor Book" uses "25" rather than "26," which results in an increase in his adjustment of approximately $70,000.

In addition to these numeric errors, Mr. Radigan's methodology is inconsistent with his opinion. Mr. Radigan's proposal is to limit the Companies' recovery to the headcount

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[11] *See* KU Response to Kroger First Request of Information, No. 11(e); LG&E Response to Kroger First Request of Information, No. 12(e).

[12] *See* Direct Testimony of Frank Radigan at Exhibit AG-3, Sch. FWR-4, Page 3 of 6 (KU Case No. 2014-00371); Direct Testimony of Frank Radigan at Exhibit AG-3, Sch. FWR-4, Page 3 of 6.

that existed as of December 31, 2014. In other words, Mr. Radigan would disallow all hires occurring after December 31, 2014. Rather than using the actual data and information related to post-December 31, 2014 hires, Mr. Radigan's opinions are based purely on a proxy that attempts to extrapolate data from April 1, 2012, through June 30, 2016, and apply it to post-December 31, 2014 hires. This is improper as Mr. Radigan has not shown that the data points are similar enough to warrant such extrapolation (i.e., that the average payroll increase per position is similar and that contractor-offset amounts are similar).

Finally, Mr. Radigan double counts a deduction for numerous Gas Distribution positions by proposing their cost be eliminated both through his proposed deduction to labor expense and through his proposed deduction to gas maintenance expense.

In sum, Mr. Radigan's opinions and methodology are so flawed and lacking that they should not be considered.

Q. Mr. Radigan takes specific exception to LG&E's decision to hire nineteen line technicians. Why is LG&E hiring line technicians?

A. Over time, more than two-thirds of LG&E's line technicians have been outsourced; many of these positions have been filled by former LG&E employees. These former employees are now retiring or approaching retirement age, and their attained skills and unique system and equipment knowledge cannot be readily replaced. This unique knowledge is essential to the operation of the Companies' electrical distribution system, especially in outages. As explained earlier, line technicians play key bird-dog roles in severe outage events. Line technicians oversee, coordinate, and manage mutual aid crews providing restoration assistance on an unknown distribution system. The Commission has recognized the importance of this role in its previous reports on severe-weather events, even calling "the availability of qualified bird-dogs" a "concern" during a large-scale outage.[13]

In addition, the Companies elected to convert select contractor line technician positions to internal positions due to an increasingly competitive job market and the transition of the Companies' workforce due to accelerating retirements. As mentioned above, new line technicians require time to reach full proficiency and be fully effective as part of the Companies' small-sized work crews. Increasing the ratio of internal-to-contractor line technicians reduces turnover risks, protects training investments, and provides for the necessary knowledge retention of the Companies' system and equipment.

Finally, each of these nineteen additions involves a corresponding contractor offset.

Q. Are the costs for each of the positions for which Mr. Radigan proposes a disallowance recovered through base rates?

A. No. Of the 92 net positions that will be hired after December 31, 2014, the costs for 16 of the positions are recovered through either the environmental-compliance surcharge ("ECR") or though the DSM mechanism. On Rebuttal Testimony Exhibit PWT-3, the positions for which cost recovery occurs outside of base rates are marked with an "X" in the column titled "Mechanism Related."

Of the 16 positions, 5 are energy efficiency operations positions to meet and implement the Companies' DSM programs as approved by the Commission, 2 of which have been filled. The costs for these 5 positions are recovered through the DSM mechanism, not through base rates.

[13] Kentucky Public Service Commission, *Final Report: Assessment of the February 2003 Ice Storm* 9 (Feb. 6, 2004); *see also* Kentucky Public Service Commission, *Ike and Ice: The Kentucky Public Service Commission Report on the September 2008 Wind Storm and the January 2009 Ice Storm* 85 (Nov. 19, 2009).

Additionally, the Companies have hired or will be hiring 11 positions related to environmental compliance, 7 of which have been filled or have an active job posting. All of these positions are within Generation, and 9 of the 11 are for engineering positions. The other 2 positions are for an equipment and instrumentation technician and a mechanic, both of which will provide support for new equipment related to environmental-compliance facilities.

PADDY'S RUN DEMOLITION

Q. Have you reviewed Mr. Kollen's recommendation to exclude the proposed demolition cost of the Paddy's Run Generating Station from LG&E's capitalization?

A. Yes. Mr. Kollen recommended removal of $11.5 million from LG&E's capitalization for costs incurred to demolish retired structures at the Paddy's Run Generating Station that deteriorated over the years and now pose a health and safety danger. The effect of this removal is to reduce LG&E's revenue requirement by $1.235 million.[14]

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

A. No. The Companies strive to deliver *safe* and reliable energy to their customers. The Companies also strive to provide a safe workplace for their employees and business partners through a "No Compromises" approach. Simply stated, the existing structures at LG&E's Paddy's Run Generating Station are no longer safe. Both the reasons for and the amount of the Companies' forecasted cost to demolish the plant are reasonable and should be recovered.

Q. Briefly describe the need to demolish the existing structures at the Paddy's Run Generating Station.

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[14] *See* Lane Kollen Direct Testimony at 53.

A. The Paddy's Run Generating Station sits on the bank of the Ohio River in western Jefferson County, Kentucky. LG&E began construction of the facilities formerly used for power production at the site in the 1930s. The last coal-fired units at Paddy's Run Generating Station were retired in the late 1970s. The existing, but no longer used, powerhouse complex was constructed in the late 1930s and into the 1940s. The powerhouse structure is an approximately 600-foot long building that has been inactive since the early 1980s. The site formerly contained five chimneys that were demolished in 2012 due to imminent structural concerns.

LG&E engaged a third-party, AMEC Environment & Infrastructure, Inc. ("AMEC"), to perform a study to determine the best measures to take with respect to the Paddy's Run powerhouse complex and related facilities. LG&E provided AMEC's study in response to KIUC 1-6(e). The facility is in a state of disrepair that is only worsening, as evidenced by the photographs included in AMEC's study. As noted in the study, the facility also contains numerous hazardous building materials, such as asbestos and lead-based paints, that were often used for construction at the time these facilities were built. Based upon AMEC's report, LG&E decided it is in the best interest of all stakeholders to demolish the existing structure. Doing so will eliminate exposure and safety risks and minimize ongoing maintenance costs.

FORECASTED GAS MAINTENANCE EXPENSE

Q. Do you agree with Mr. Radigan's recommendation to reduce LG&E's revenue requirement by $1,581,447 for gas maintenance expense?

A. No. Mr. Radigan suggests the elimination of $1,581,447 in forecasted gas maintenance expense.[15] He identifies 13 expense accounts that contain a difference between the base period and the test period.[16] He claims that LG&E has not met its burden in proving that the differences between the base period and test period amounts for these accounts are reasonable. Mr. Radigan claims that he found no testimony, responses to data requests, nor any other evidence in the record as to the reasonableness of the differences between the two periods. Interestingly, of the 13 accounts identified by Mr. Radigan, LG&E projects the forecasted expense in five of them to be *less* in the test period than in the base period.

Q. Does the record contain sufficient evidence to prove the reasonableness of the differences between the base period and test period in those 13 accounts?

A. Yes. Schedule D-1, which was attached to LG&E's Application, provides the differences between the base period and test period and provides an explanation for those differences. In fact, those explanations are repeated verbatim in the chart Mr. Radigan provided as part of his testimony on this issue. For example, the variance in account number 887, Maintenance of Mains, was explained with the following statement, "variance reflects higher pipeline integrity costs, higher test and reconnect work (offset in account 879), higher trouble/dispatch work in the forecasted period." For each of the accounts Mr. Radigan identifies, a similar explanation was provided in Schedule D-1.

Additionally, although Mr. Radigan claims there are no responses to data requests related to these accounts, he is mistaken. PSC 2–83 specifically asked for more information concerning accounts 834 and 836, both of which are on Mr. Radigan's list.

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[15] *See* Direct Testimony of Frank Radigan at 16 (LG&E Case No. 2014-00372).
[16] The 13 accounts are: 818, 819, 821, 834, 836, 850, 851, 856, 863, 879, 887, 891, and 894.

LG&E's response to that data request provided very specific information about the forecasted expense for that account.[17] Similarly, PSC 2-84 sought more information related to the variance in account 863 related to in-line inspections. LG&E provided additional information in its response. Then, in PSC 3-25, Commission Staff asked for more information about in-line inspections and LG&E provided that information for the three lines that were identified in PSC 2-84 (Riverport Line, Ballardsville Line, and Western Kentucky C line). Therefore, Mr. Radigan is mistaken when he says the record contains no information about the account variances between base period and test period. Of course, to the extent Mr. Radigan had questions in discovery about any of the 13 accounts, the Attorney General could have asked those questions and LG&E would have responded to them in the same manner as LG&E responded to Commission Staff's questions.

Q. In addition to the information LG&E already provided in Schedule D-1 and in response to data requests, are there other reasons behind the increased amounts in Accounts 818, 834, 836, and 856?

A. Yes. In relation to the Company's Muldraugh and Magnolia compressor stations,[18] the forecasted increases in expense are driven by headcount additions ($180,000), purifier and dehydrator cleaning ($75,000), tree trimming ($150,000), additional chemical purchases ($50,000) and general inflation ($223,000 at an assumed 2.5%).

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[17] For Account 834, LG&E explained that there were some offsetting amounts from other accounts, headcount additions, tree trimming, additional chemical purchases, and purifier and dehydrator cleaning. For Account 836, LG&E explained that the cleaning of purifier units and work on regenerator towers were reasons for the expense in this account and that some of the increase would be offset by lower amounts in other accounts. LG&E also explained that the same headcount additions, tree trimming, chemical purchases and purifier/dehydrator cleaning were reasons for the increase in Account 836.

[18] The FERC accounts that represent those expense activities managed from Muldraugh and Magnolia are 814, 816, 817, 818, 819, 821, 830, 832, 833, 834, 835, 836, 850, 856, 863, 874, 878, 879, 880, 887,889, 892, and 926.

Q. In addition to the information LG&E already provided in Schedule D-1 and in response to data requests, please explain the increased amount in Account 863.

A. In response to PSC 2-84 and PSC 3-25, LG&E explained that the increased amount in Account 863 is driven by an increase in in-line inspection costs. In-line inspection projects are scheduled in accordance with federally mandated pipeline safety regulations to ensure the integrity of gas transmission lines. Inspections of the Company's Ballardsville and Riverport lines are scheduled to occur in either 2015 or 2016 in accordance with those regulations while the Magnolia line was inspected in 2014. Additionally, the inspection of the Western Kentucky C pipeline, while not federally mandated, will be inspected in accordance with NTSB recommendations.

Q. In addition to the information provided in Schedule D-1, please explain the increased expense in Account 887.

A. Schedule D-1 explained that higher pipeline integrity costs, higher test and reconnect work, and higher trouble/dispatch work cause an increased expense in the test period. Pipeline integrity costs are higher in the test period due to higher labor, outside services, and materials costs. Pipeline integrity costs in the base period were low due to labor diverted to capital projects and less engineering services. Pipeline integrity costs in the test year are also higher due to one incremental employee hire, consulting services for analysis of possible findings related to corrosion and integrity management, and more anticipated repairs.

Q. Did Mr. Radigan remove some of the same expenses twice in his recommendations?

A. Yes, Mr. Radigan appears to have "double counted" or removed some of the same expenses twice in his recommended adjustments to LG&E revenue requirement. When he recommends removal of additional headcount expense *and* gas maintenance expense, to the extent gas maintenance expense includes additional headcount, Mr. Radigan has removed the same dollars twice. As explained above, LG&E explained in discovery that the projected expense for several of the accounts in question included additional headcount expense. For these accounts, Mr. Radigan's proposed reductions for headcount and gas maintenance overlap and would result in reducing the same expense twice.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is Chief Operating Officer 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.

Paul W. Thompson

Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of April 2015.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

Dept	Title	# of positions	Business Need	Further Details Explaining Business Need	Contractor Offset
Generation	Chemical Engineer	3	Capital Projects		0
Generation	Civil Engineer	1	Capital Projects		0
Generation	Electrical Engineer	3	Capital Projects		0
Generation	Mechanical Engineer	1	Capital Projects		0
Generation	Mgr Major Capital Projects	1	Capital Projects		0
Generation	Project Coordinator	9	Capital Projects		0
Generation	Boiler Welding QA/QC Specialist	1	Core Skill Building/Knowledge Retention and Transfer	Strengthen the Boiler and Reliability Programs improvement initiatives.	0
Generation	Buyer	2	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement (1) and Delayed Sourcing Asst to future year, utilized vacancy to hire Buyer for CR7 Support (1)	0
Generation	CCS Administrative Coordinator	1	Core Skill Building/Knowledge Retention and Transfer	Administrative Support for the TG department.	0
Generation	Civil Engineer	4	Core Skill Building/Knowledge Retention and Transfer	Large scale CIR and LGE Projects (1), Major Capital Projects (1), Ash Ponds and water compliance (1), Long and Short-Term Management of Landfill (1)	0
Generation	Commercial Ops Analyst	1	Core Skill Building/Knowledge Retention and Transfer	Contract Administrator position was advanced, this was utilized to create a Manager position.	0
Generation	Compliance Engineer	1	Core Skill Building/Knowledge Retention and Transfer	Backfill	0
Generation	Consumer Behavioral Analyst	1	Core Skill Building/Knowledge Retention and Transfer	Rapidly and significantly advance our forecasting analysis capabilities.	0
Generation	Contract Administrator	3	Core Skill Building/Knowledge Retention and Transfer	Increase in the demand for project/outage specific bidding and contracting services has increased across the fleet (3)	0
Generation	Dept/Div Secretary	1	Core Skill Building/Knowledge Retention and Transfer	Cyber security records support and other records support.	0
Generation	Dir. Fleet Maint Perfm & Reliab	1	Core Skill Building/Knowledge Retention and Transfer	Responsible for analysis, strategic direction, and standardization of work management processes and initiatives across the generating fleet and direct the efforts of the Turbine Maintenance and Central Service Shop teams.	0
Generation	Drafter	1	Core Skill Building/Knowledge Retention and Transfer	Backfill	0
Generation	E&I Technician	5	Core Skill Building/Knowledge Retention and Transfer	Backfill (3) and Controls and Maintenance related to addition of new tech and equipment (2)	0
Generation	Electrical Engineer	3	Core Skill Building/Knowledge Retention and Transfer	Backfill (1), Major Capital Projects (1) and knowledge sharing of fleet electrical systems and in house technical expertise for NERC Reliability compliance challenges (1)	0
Generation	Engineer	2	Core Skill Building/Knowledge Retention and Transfer	Major Capital Projects (2)	0
Generation	Group Leader - Engineering	1	Core Skill Building/Knowledge Retention and Transfer	Formal supervision, leadership, and employee development associated with bringing more engineering in-house.	0
Generation	I&E Maintenance Planner	1	Core Skill Building/Knowledge Retention and Transfer	Prefill for retirement	0
Generation	I&E Technician (SAM)	1	Core Skill Building/Knowledge Retention and Transfer	Controls and maintenance related to increased air quality monitoring regulations SAM/CAM.	0
Generation	Lab Assistant	1	Core Skill Building/Knowledge Retention and Transfer	Additional workload due to monitoring, new equipment and landfill operations requirements.	0
Generation	Lab Tech	1	Core Skill Building/Knowledge Retention and Transfer	Additional workload due to landfill operations requirements and to support FGD/pulverizer operations.	0

Dept	Title	# of positions	Business Need	Further Details Explaining Business Need	Contractor Offset
Generation	Maintenance Tech	10	Core Skill Building/Knowledge Retention and Transfer	Shortage of IE resources (3), Increased mechanical maintenance corrective and preventive workload due to CCP equipment (3), Backfill (1) and techs to maintain new equipment related to PJFF, CCR, and sorbent injection systems (3)	0
Generation	Material Handling Leader	1	Core Skill Building/Knowledge Retention and Transfer	Provide for the direct LG&E leadership monitoring, directing, coordinating activity within the Material Handling areas with increased use of variable work force.	0
Generation	Mechanic	1	Core Skill Building/Knowledge Retention and Transfer	Needed to maintain new equipment related to PJFF, CCR, and sorbent injection systems	0
Generation	Mechanical Engineer	10	Core Skill Building/Knowledge Retention and Transfer	Project management and engineering technical support related to new plant build and new technologies (3), Strengthen the Boiler and Reliability Programs improvement initiatives (1), Support the expanding preventive maintenance program (3), Expanding performance monitoring Program and VISTA management (1) and Support plant performance engineering processes (2)	0
Generation	OF Turbine Mechanic	2	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirements	0
Generation	Operator/Production Leader	9	Core Skill Building/Knowledge Retention and Transfer	Currently each watch (4 total) has 10 operators. The primary responsibilities of the additional one operator per watch would be used to split the AQCS equipment from the exit of the SCR to the stack between TC1 and TC2 as well as help provide relief for longer term items (8) and position converted to training coordinator - Implementation of "power generation training plan", including compliance, technical, leadership, and safety training initiatives.	0
Generation	Production Leader	1	Core Skill Building/Knowledge Retention and Transfer	Position converted to Trainer. Develop, track, and deliver plant operations and maintenance training initiatives related to technical, leadership, and safety.	0
Generation	R&D/Scientist	5	Core Skill Building/Knowledge Retention and Transfer	Backfill (1), Evaluate, follow and track emerging technologies to optimize our R&D portfolio (2), Hg focus for the lab (1) and Focus on Environmental compliance	0
Generation	Service Shop Coordinator	1	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement	0
Generation	Sourcing Assistant	1	Core Skill Building/Knowledge Retention and Transfer	Major Capital Projects	0
Generation	Sr. Labor Distribution Clerk/Timekeeper	2	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement	0
Generation	Supervisor - Maintenance	1	Core Skill Building/Knowledge Retention and Transfer	Supervise, plan, monitor clerical functions and personnel associated with both short and long-term mechanical maintenance.	0
Generation	Supply Mkt and Inv Analyst	1	Core Skill Building/Knowledge Retention and Transfer	Consolidating the LKE fleet-wide data gathering and analytics expertise to this position allows the supply base focused staff to concentrate on executing the strategies and tactics that delivers the value rather than data mining and consolidation.	0

Dept	Title	# of positions	Business Need	Further Details Explaining Business Need	Contractor Offset
Generation	Technician/Mntc Leader	4	Core Skill Building/Knowledge Retention and Transfer	Backfill (1), Continuing adequate support to the TC maintenance department (1) and Prefill for Retirement (2)	0
Generation	Trainer	2	Core Skill Building/Knowledge Retention and Transfer	New position to develop, track, and deliver plant operations and maintenance training initiatives related to technical, leadership, and safety.	0
Generation	Turbine Specialist	2	Core Skill Building/Knowledge Retention and Transfer	Backfill (2)	0
Generation	Warehouse Supervisor	1	Core Skill Building/Knowledge Retention and Transfer	Adding this position will be necessary In order ensure we are effectively planning, coordinating and administering all facets of the purchasing and inventory management activities.	0
Generation	Dir ES Business Information	-1	Corporate Reorganization		0
Generation	ES SR. Business Info Analyst	-1	Corporate Reorganization		0
Generation	Mgr Eng Serv Business Info	-1	Corporate Reorganization		0
Generation	Mgr. Ops Analysis	-1	Corporate Reorganization		0
Generation	Chief Operating Officer	-2	Corporate Reorganization		0
Generation	Green River transfer to metering	-11	Plant retirement		0
Generation	Manager- Tyrone	-1	Plant retirement		0
Generation	Green River retirement	-15	Plant retirement		0
Generation	Cane Run Retirement	-25	Plant retirement		0
Generation	CCR Supervisor	1	Regulatory Compliance		0
Generation	CIP Clerk	1	Regulatory Compliance		0
Generation	CIP Control Specialist	1	Regulatory Compliance		0
Generation	Control Specialist	1	Regulatory Compliance		0
Transmission	Cascade Analyst	1	Core Skill Building/Knowledge Retention and Transfer	Cascade was purchased and installed to provide a tool to track maintenance activity associated with both good utility practice and ensure compliance with NERC reliability standards including documentation of compliance evidence(primarily PRC-005). Analyst support is needed for daily support of the program, coordination of activities and record security and accuracy.	0
Transmission	Drafting Technician	3	Core Skill Building/Knowledge Retention and Transfer	Provide electronic and manual prints drafting and design support and updates to assist engineering staff and ensure system prints and equipment specifications are accurately documented.	3
Transmission	Electrical Engineer	1	Core Skill Building/Knowledge Retention and Transfer	Planning Engineer needed to support TPL transmission system planning standards (TOP-002, TPL-001, CIP-014, PRC-006, TPL-007, and to complete routine planning studies needed for reliable real time operations and to develop the annual Transmission Expansion Plan that is used to determine long term projects that are required to be constructed to prevent violations of reliability criteria.	0
Transmission	Group Leader Substation Asset Mgmt	1	Core Skill Building/Knowledge Retention and Transfer	Needed to provide dedicated leadership of asset management, maintenance program oversight and daily administration of CASCADE and maintenance of critical asset technical data and testing records.	0

Dept	Title	# of positions	Business Need	Further Details Explaining Business Need	Contractor Offset
Transmission	Lines Inspector	3	Core Skill Building/Knowledge Retention and Transfer	The increase in the number of transmission projects and associated transmission line construction contractors required to meet compliance with Transmission Planning standards (TPL) and Transmission planning guidelines made it necessary to add transmission line inspectors for contractor safety, coordination, and oversight of quality and performance.	1
Transmission	Mgr Transmission Substation, Eng., Constr., Maint	1	Core Skill Building/Knowledge Retention and Transfer	Provide leadership due to department restructuring driven by increased work due to NERC reliability standards, subsequent CIP standards (including PRC-004, PRC-005, PRC-023, CIP-002 thru CIP-009, CIP-014), and increase in capital investment projects. The increase no longer permitted a single manager the ability to effectively manage both substation as well as protection and control for all transmission assets.	0
Transmission	Planning Engineer	2	Core Skill Building/Knowledge Retention and Transfer	Backfill (1) and addition needed to support TPL transmission system planning standards (TOP-002, TPL-001, CIP-014, PRC-006, TPL-007, and to complete routine planning studies needed for reliable real time operations and to develop the annual Transmission Expansion Plan that is used to determine long term projects that are required to be constructed to prevent violations of reliability criteria.	0
Transmission	Planning Engineer	1	Regulatory Compliance		0
Transmission	Project Coordinator	1	Capital Projects		0
Transmission	Protection/Relay Technician	3	Core Skill Building/Knowledge Retention and Transfer	Provide technical support, testing and maintenance related to reliability compliance standards (PRC-005) and for commissioning of new capital work.	2
Transmission	Protection/Relay Technician	1	Capital Projects		0
Transmission	Protection Engineer	2	Regulatory Compliance		0
Transmission	Substation Inspector	2	Core Skill Building/Knowledge Retention and Transfer	The increase in the number of transmission projects and associated transmission substation construction contractors required to meet compliance with Transmission Planning standards (TPL) and Transmission planning guidelines made it necessary to add transmission substation inspectors for contractor safety, coordination, and oversight of quality and performance.	1
Transmission	System Control Engineer	1	Regulatory Compliance		0

Dept	Title	# of positions	Business Need	Further Details Explaining Business Need	Contractor Offset
Transmission	System Control Engineer	1	Core Skill Building/Knowledge Retention and Transfer	Daily technical support for the transmission system control center including support for the operations simulator used for training, effective use of EMS tools in support of reliable operations and compliance assistance for NERC Reliability Standards including Transmission Operations (TOP), Emergency Preparedness and Operations (EOP), Resource and Demand Balancing (BAL), Interchange Scheduling and Coordination (INT), and Personnel Performance, Training, and Qualifications (PER-005).	0
Transmission	System Administrator	-4	Corporate Reorganization		0
Transmission	Safety Coordinator	-1	Corporate Reorganization		0
Transmission	Contract Coordinator	-1	Position not backfilled		0
Transmission	Cascade Administrator	1	Core Skill Building/Knowledge Retention and Transfer	Provide administrative and analytical support to ensure effective planning and tracking of maintenance activities and accurate documentation.	1
Distribution	Computer Graphics Technician	2	Core Skill Building/Knowledge Retention and Transfer	Backfill (1) and Prefill for Retirement (1)	0
Distribution	Distribution operations Assistant	1	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement	0
Distribution	Electrical Apprentice	6	Core Skill Building/Knowledge Retention and Transfer	Contractor offset (5) and Prefill for Retirement (1)	5
Distribution	Electrical Engineer	1	Core Skill Building/Knowledge Retention and Transfer	Contractor offset	1
Distribution	Electrical Engineer (Danville)	1	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement	0
Distribution	Electrical Engineer (Maysville)	1	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement	0
Distribution	Electrical Engineer (SC&M)	1	Core Skill Building/Knowledge Retention and Transfer	Contractor offset	1
Distribution	Electrical Engineer (System Planning)	1	Core Skill Building/Knowledge Retention and Transfer	Allow for knowledge transfer from only engineer who does work on standards in advance of retirement.	0
Distribution	Engineer (Reliability)	1	Core Skill Building/Knowledge Retention and Transfer	Contractor offset	1
Distribution	Engineer Design Tech	1	Core Skill Building/Knowledge Retention and Transfer	Contractor offset	1
Distribution	Engineer Design Tech (Danville)	1	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement	0
Distribution	Facility Records Technician	3	Core Skill Building/Knowledge Retention and Transfer	Contractor offset (3)	3
Distribution	Field Coordinator	3	Core Skill Building/Knowledge Retention and Transfer	Contractor offset (3)	3
Distribution	Line Technician (Greenville)	1	Core Skill Building/Knowledge Retention and Transfer	Backfill	0
Distribution	Line Technician (Louisville)	19	Core Skill Building/Knowledge Retention and Transfer	Contractor offset (16) and Backfill (3)	16
Distribution	Line Technician (Pineville)	1	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement	0
Distribution	Line Technician (Richmond)	1	Core Skill Building/Knowledge Retention and Transfer	Contractor offset	1
Distribution	Mechanic Helper	1	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement	0
Distribution	Network Technician	6	Core Skill Building/Knowledge Retention and Transfer	Contractor offset (6)	6
Distribution	Project Coordinator	1	Core Skill Building/Knowledge Retention and Transfer	Manage and improve 3rd party pole attachment process and allow for knowledge transfer in advance of retirement	0
Distribution	Records Coordinator	2	Core Skill Building/Knowledge Retention and Transfer	Backfill	0
Distribution	Restoration Coordinator	2	Core Skill Building/Knowledge Retention and Transfer	Contractor offset (1) and Support during high volume events and allow for more training and succession planning (1)	1
Distribution	SC&M Coordinator Analyst	1	Core Skill Building/Knowledge Retention and Transfer	Contractor offset	1
Distribution	Utility Arborist	1	Core Skill Building/Knowledge Retention and Transfer	Contractor offset	1
Distribution	Sr. Distribution operations assistant	-1	Core Skill Building/Knowledge Retention and Transfer		0
Distribution	Substation Tech	-1	Core Skill Building/Knowledge Retention and Transfer		0
Distribution	Sys Admin	-3	Core Skill Building/Knowledge Retention and Transfer		0

Dept	Title	# of positions	Business Need	Further Details Explaining Business Need	Contractor Offset
Distribution	Team Leader (SC&M)	-1	Core Skill Building/Knowledge Retention and Transfer		0
Customer Services	AMR Tech	1	Regulatory Compliance		0
Customer Services	Area Retail Operations Manager	1	Customer Service		0
Customer Services	Billing Analysis Associate	1	Core Skill Building/Knowledge Retention and Transfer	It takes 12-18 months of on the job training to become proficient in billing; Over the last three years billing integrity has seen the average tenure of its team diminish from an average of 25 years of billing experience to its current level of less than ten years of billing experience.	0
Customer Services	Billing Analysis Associate	3	Customer Service		0
Customer Services	Call Center Business Analyst	2	Customer Service		0
Customer Services	Call Center Performance Operations rep	1	Customer Service		0
Customer Services	Call Center QA Rep	1	Customer Service		0
Customer Services	Call Center Representative (Morganfield)	10	Customer Service		0
Customer Services	CIP Associate	1	Regulatory Compliance		0
Customer Services	CIP Coordinator	1	Regulatory Compliance		0
Customer Services	Corp Security Secretary	1	Core Skill Building/Knowledge Retention and Transfer	Assist the Corporate Security/Business Continuity with administrative activities including NERC/CIP compliance work processes and responsibilities	0
Customer Services	Customer Care Coach	2	Customer Service		0
Customer Services	Customer Relations Associate	1	Core Skill Building/Knowledge Retention and Transfer	Contractor offset due to high temporary contractor turnover	1
Customer Services	Customer Representative - Business Office	15	Customer Service		15
Customer Services	Customer Representatives - Residential Call Center	16	Customer Service		0
Customer Services	Dept/Div Secretary	2	Core Skill Building/Knowledge Retention and Transfer	Contractor conversion (2)	2
Customer Services	Electric Meter Tech	1	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement	0
Customer Services	Electrical Engineer	1	Core Skill Building/Knowledge Retention and Transfer	Needed skill sets to handle the ever increasing complexity in software and hardware related to the meters.	0
Customer Services	Energy Efficiency	4	Customer Service		0
Customer Services	Gas Meter Mechanic Helper	1	Core Skill Building/Knowledge Retention and Transfer	Retirement offset of a contractor.	1
Customer Services	Gas Meter Shop Supervisor	1	Core Skill Building/Knowledge Retention and Transfer	Retirement offset of a contractor.	1
Customer Services	Manager Facilities Construction and Space Utilization	1	Core Skill Building/Knowledge Retention and Transfer	Ensure cross training and	0
Customer Services	Manager ROW	1	Core Skill Building/Knowledge Retention and Transfer	Ensure cross training of current employees in legal requirements of each role, documentation and harmonization of all processes and procedures r.	0
Customer Services	Manager, Facility Services	1	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement	0
Customer Services	Meter Reader	11	Regulatory Compliance		0
Customer Services	Meter Reading Process Analyst	1	Core Skill Building/Knowledge Retention and Transfer	Provide and analyze meter reading processes and reports to make recommendations on business strategies to gain operational efficiencies	11
Customer Services	Program Manager	1	Customer Service		0
Customer Services	ROW Agent	7	Core Skill Building/Knowledge Retention and Transfer	Centralize RoW function through dedicated agents throughout our KU territory (7)	1
Customer Services	Security Technical Assistant	1	Regulatory Compliance		1
Customer Services	Supervisor Corp Facility Services	1	Core Skill Building/Knowledge Retention and Transfer	Oversee the Company’s lease agreement with building owner to ensure all lease provisions are properly executed and terms and conditions of the lease are fulfilled at the corporate facility. (1)	0

Dept	Title	# of positions	Business Need	Further Details Explaining Business Need	Contractor Offset
Customer Services	Supervisor Facility Operations	2	Core Skill Building/Knowledge Retention and Transfer	Positions needed to address the volume of customer requests for facility maintenance across KU's Central and North East service territories	0
Customer Services	Meter Tech	-1	Core Skill Building/Knowledge Retention and Transfer		0
Safety & Technical training	Safety Specialist	3	Core Skill Building/Knowledge Retention and Transfer	Positions responsible for developing and delivering technical, compliance and safety training of the distribution and transmission operations organizations. Positions serve as technical consultant supplying expertise on technical procedures, compliance and safety practices to all levels of management, field employs and company contractors.	0
Safety & Technical training	Fire and Security Investigator	1	Corporate Reorganization		0
Safety & Technical training	Manager, ED and Transmission Safety	1	Corporate Reorganization		0
Safety & Technical training	Manager, Gas Distribution Safety	1	Core Skill Building/Knowledge Retention and Transfer	Leads all Gas Distributions Operations safety. Responsible for planning, directing and coordination of safety programs, policies and procedures that support strategic initiatives of the business.	0
Safety & Technical training	Safety Coordinator	1	Corporate Reorganization		0
Safety & Technical training	Training Consultant	1	Core Skill Building/Knowledge Retention and Transfer	Provide technical training and development essential to Gas Distribution Operations.	0
Safety & Technical training	Safety Metrics Analyst	1	Core Skill Building/Knowledge Retention and Transfer	Position responsible for researching, analyzing, data for internal and external reporting of the company's safety performance.	0
Safety & Technical training	Health and Safety Coordinator	-1	Core Skill Building/Knowledge Retention and Transfer		0
Gas	Administrative Assistant Gas Construction	1	Capital Projects		1
Gas	Auxiliary Operator	1	Core Skill Building/Knowledge Retention and Transfer	The addition of equipment; particularly off-site, has placed a need for an additional employee.	0
Gas	Corrosion Analyst	1	Regulatory Compliance		0
Gas	Corrosion Tech	1	Regulatory Compliance		0
Gas	CRM Compliance Training Specialist	1	Regulatory Compliance		0
Gas	Damage Investigator	1	Regulatory Compliance		1
Gas	Data Planning Analyst	1	Core Skill Building/Knowledge Retention and Transfer	Identify data integrity issues as information is collected from field employees, plan short duration jobs (service line installations, replacements)	0
Gas	Director Gas Operations, Construction, Engineering	1	Regulatory Compliance		0
Gas	Distribution Mechanic	5	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirements	0
Gas	Engineer	4	Regulatory Compliance		0
Gas	Engineer/Scientist	1	Regulatory Compliance		0
Gas	FTD Distribution Mechanic	1	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement	0
Gas	Gas Analyst	1	Regulatory Compliance		0
Gas	Gas Construction Manager/Group Leader	4	Regulatory Compliance		0
Gas	Gas Controller	2	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement; Gas Controller requires at least twelve months of training for a new hire to backfill this Gas Controller position to the minimum proficiency and no current feeder group exists for this position.	0
Gas	Gas Dispatcher	1	Regulatory Compliance		0
Gas	Gas Engineer	2	Capital Projects		0

Dept	Title	# of positions	Business Need	Further Details Explaining Business Need	Contractor Offset
Gas	Gas Engineer	2	Core Skill Building/Knowledge Retention and Transfer	Support the existing programs along with providing an engineer resource for projects and work execution functions	0
Gas	Gas Regulatory Associate	1	Regulatory Compliance		0
Gas	Gas Regulatory Associate	5	Core Skill Building/Knowledge Retention and Transfer	Contractor conversions; turnover is common amongst the work group as a result of the positions not being LG&E employees.	5
Gas	Gas Supply Specialist	1	Core Skill Building/Knowledge Retention and Transfer	Developing an understanding of the more complex gas supply issues generally takes 3 to 5 years. There are no existing resources at the Gas Supply Specialist level which can be developed to address gas supply planning, contract negotiation, and regulatory expertise.	0
Gas	IM&E Technician	3	Core Skill Building/Knowledge Retention and Transfer	Support the growing work load associate with operating and maintaining the unique measurement, pneumatic, control, instrumentation, mechanical, and electrical equipment in the Magnolia Compressor Station	0
Gas	Manager, Gas Storage Operations	1	Regulatory Compliance		0
Gas	Pipeline Inspector	1	Regulatory Compliance		0
Gas	Project Engineer Muldraugh	1	Regulatory Compliance		0
Gas	Project Planner/Scheduler	1	Capital Projects		0
Gas	Riser Team Leader	1	Regulatory Compliance		0
Gas	SR&O Technician	3	Core Skill Building/Knowledge Retention and Transfer	Prefill for Retirement	0
Gas	Team Leader, Gas Construction	1	Core Skill Building/Knowledge Retention and Transfer	Supervisory support is needed due to department tripling over the last 10 years due to increased contract construction.	0
Gas	(-1) Storage Operator	-1	Core Skill Building/Knowledge Retention and Transfer		0
Gas	(-1)Trouble Technician	-1	Core Skill Building/Knowledge Retention and Transfer		0
Gas	(-1)SR&O Technician	-1	Core Skill Building/Knowledge Retention and Transfer		0
Gas	(-1)Distribution Mechanic	-1	Core Skill Building/Knowledge Retention and Transfer		0
Gas	(-1)Distribution Mechanic	-1	Core Skill Building/Knowledge Retention and Transfer		0
Gas	(-1)FTD Distribution Mechanic	-1	Core Skill Building/Knowledge Retention and Transfer		0
Gas	(-1)Gas Controller	-1	Core Skill Building/Knowledge Retention and Transfer		0
Gas	(-1)SR&O Technician	-1	Core Skill Building/Knowledge Retention and Transfer		0

	Full Year		
Key Metrics	**2009**	**2014**	**% 2014 Change**
Call Center Service Level 80% in 30 Seconds	30.9%	83.5%	170%
Combined Abandonment Rate [%]	22.5%	2.7%	-88%
Combined Email Service Level within 24 Hours [%]	23.6%	98.0%	315%
Combined Calls Routed to Overflow	608,336	1,259	-100%
Kentucky Public Service Commission Inquiries	955	363	-62%

	Period of Time		
Customer Satisfaction Surveys	**2010 Partial Year**	**2014**	**% 2014 Change**
Residential Service Center – Agent Answer Calls [10 point scale] (a)	8.46	9.29	10%
Business Service Center – Agent Answered Calls [10 point scale] (b)	8.83	9.28	5%
Residential Answered Emails [10 point scale] (c)	7.07	8.75	24%

(a) Began tracking in July 2010
(b) Began tracking in June 2010
(c) Began tracking in August 2010
Note: Email survey for residential contacts only.

Department	Position	No. of positions	Payroll expense $	Base year	Test year	Status of 3/31/15	Mechanism Related	Justification of positions not yet filled
Administrative	Environmental Scientist	1	213,658	x		Filled		N/A
Administrative	Rates Analyst	1	93,391	x		Filled		N/A
Administrative	Manager, Corporate Responsibility	1	131,100	x		Filled		N/A
Customer Service	Customer Representatives - Residential Call Center	6	170,286	x		Filled		N/A
Customer Service	Call Center QA Rep	1	42,524	x		Filled		N/A
Customer Service	Energy Efficiency	2	160,188	x		Filled	X -DSM	N/A
Customer Service	Customer Relations Associate	1	35,277	x		Filled		N/A
Electric Distribution	Facility Records Technician	1	42,082	x		Filled		N/A
Electric Distribution	Line Technician (Louisville)	10	625,400	x		Filled		N/A
Electric Distribution	Electrical Apprentice	3	159,000	x		Filled		N/A
Electric Distribution	Facility Records Technician	1	41,340	x		Filled		N/A
Electric Distribution	Electrical Engineer (SC&M)	1	81,096	x		Filled		N/A
Electric Distribution	SC&M Coordinator Analyst	1	95,920	x		Filled		N/A
Electric Distribution	Electrical Engineer (System Planning)	1	81,096	x		Filled		N/A
Electric Distribution	Engineer (Reliability)	1	70,741	x		Filled		N/A
Electric Distribution	Electrical Apprentice	2	106,000		x	Filled		N/A
Electric Distribution	Electrical Engineer (Maysville)	1	81,096		x	Filled		N/A
Gas Distribution	Gas Supply Specialist	1	73,030	x		Filled		N/A
Generation	Electrical Engineer	1	193,364	x		Filled		N/A
Generation	Mechanical Engineer	1	82,287	x		Filled		N/A
Generation	Project Coordinator	1	76,801	x		Filled		N/A
Generation	Commercial Ops Analyst	1	77,935	x		Filled		N/A
Generation	Compliance Engineer	1	89,816	x		Filled		N/A
Generation	Drafter	1	79,747	x		Filled		N/A
Generation	E&I Technician	2	238,407	x		Filled		N/A
Generation	Maintenance Tech	4	306,036	x		Filled		N/A
Generation	Mechanic	1	154,062	x		Filled		N/A
Generation	Trainer	1	94,346	x		Filled		N/A
Generation	Turbine Specialist	1	114,445	x		Filled		N/A
Generation	Chemical Engineer	1	90,901		x	Filled		N/A
Generation	Civil Engineer	1	86,611		x	Filled	X	N/A
Generation	Mechanical Engineer	1	329,148		x	Filled		N/A
Generation	Operator	1	81,941		x	Filled		N/A
Information Technology	Computer Operator Associate	1	48,066	x		Filled		N/A
Information Technology	Tech Support Analyst	2	106,542	x		Filled		N/A
Information Technology	Telecom Engineer	2	204,234	x		Filled		N/A
Information Technology	Network Systems Engineer	2	176,742	x		Filled		N/A
Information Technology	Telecom Technician	1	132,218	x		Filled		N/A
Information Technology	Database Administrator	1	120,750	x		Filled		N/A
Information Technology	Programmer Analyst	1	415,535	x		Filled		N/A
Information Technology	Workstation System Support	1	70,702	x		Filled		N/A
Information Technology	Service Desk Analyst	1	53,271	x		Filled		N/A
Transmission	Civil Engineer	1	67,580	x		Filled		N/A
Transmission	Cascade Administrator	1	101,152		x	Filled		N/A
Transmission	Drafting Technician	2	130,768		x	Filled		N/A
Transmission	Substation Inspector	1	112,150		x	Filled		N/A
Customer Service	Billing Analysis Associate	1	38,018	x		Pending start date - Offer Accepted/Offer Given		N/A
Electric Distribution	Computer Graphics Technician	1	47,700	x		Pending start date - Offer Accepted/Offer Given		N/A
Electric Distribution	Line Technician (Pineville)	1	76,320	x		Pending start date - Offer Accepted/Offer Given		N/A
Electric Distribution	Electrical Engineer (Danville)	1	81,096		x	Pending start date - Offer Accepted/Offer Given		N/A
Gas Distribution	Gas Engineer	1	68,286	x		Pending start date - Offer Accepted/Offer Given		N/A
Gas Distribution	Team Leader, Gas Construction	1	92,650	x		Pending start date - Offer Accepted/Offer Given		N/A
Gas Distribution	Administrative Assistant Gas Construction	1	38,150	x		Pending start date - Offer Accepted/Offer Given		N/A
Gas Distribution	IM&E Technician	2	99,524		x	Pending start date - Offer Accepted/Offer Given		N/A
Generation	E&I Technician	1	238,407	x		Pending start date - Offer Accepted/Offer Given		N/A
Information Technology	Programmer Analyst	1	415,535	x		Pending start date - Offer Accepted/Offer Given		N/A
Transmission	Lines Inspector	1	94,623		x	Pending start date - Offer Accepted/Offer Given		N/A
Administrative	Environmental Scientist	1	213,658	x		Active Posting		N/A
Customer Service	Supervisor Facility Operations	1	183,670		x	Active Posting		N/A
Electric Distribution	Field Coordinator	3	236,274		x	Active Posting		N/A
Gas Distribution	Project Planner/Scheduler	1	92,650	x		Active Posting		N/A
Gas Distribution	CRM Compliance Training Specialist	1	90,252		x	Active Posting		N/A
Gas Distribution	Engineer/Scientist	1	69,760		x	Active Posting		N/A
Gas Distribution	Data Planning Analyst	1	54,500		x	Active Posting		N/A
Gas Distribution	Gas Regulatory Associate	5	185,500		x	Active Posting		N/A
Gas Distribution	Damage Investigator	1	53,000		x	Active Posting		N/A
Generation	Civil Engineer	1	86,611	x		Active Posting	X	N/A

Department	Position	No. of positions	Payroll expense $	Base year	Test year	Status of 3/31/15	Mechanism Related	Justification of positions not yet filled
Generation	Mechanical Engineer	1	82,287	x		Active Posting	X	N/A
Generation	Mechanical Engineer	3	329,148		x	Active Posting	X	N/A
Generation	Engineer	1	80,946	x		Active Posting	X	N/A
Information Technology	Telecom Technician	1	132,218	x		Active Posting		N/A
Information Technology	IT Systems Engineer	1	88,371	x		Active Posting		N/A
Information Technology	Programmer Analyst	2	415,535	x		Active Posting		N/A
Safety and Technical Training	Training Consultant	2	188,694		x	Active Posting		N/A
Transmission	Protection/Relay Technician	1	76,846	x		Active Posting		N/A
Administrative	Rates Analyst	1	93,391		x	Not yet filled		New or enhanced regulations and the associated regulatory scrutiny continue to escalate at both the state and federal level.
Customer Service	Call Center Business Analyst	1	70,850	x		Not yet filled		Ensure compliance with KPSC Management Audit Recommendation – Recommendation 2
Customer Service	Customer Representatives	4	119,992	x		Not yet filled		As customers desire more information about their utility service (i.e., billing questions, rate increases, smart grid technologies, net metering, electric vehicles and energy efficiency programs) Customer Representatives must be prepared to handle more complex issues that require additional training and longer handle times for customer transactions.
Customer Service	Customer Representative - Business Office	2	59,360	x		Not yet filled		As customers desire more information about their utility service (i.e., billing questions, rate increases, smart grid technologies, net metering, electric vehicles and energy efficiency programs) Customer Representatives must be prepared to handle more complex issues that require additional training and longer handle times for customer transactions.
Customer Service	Energy Efficiency	2	160,188	x		Not yet filled	X - DSM	Program Development and Administration due to growth of the program — adding staff to perform market segmentation, procurement and contract administration, and evaluation measurement and verification.
Customer Service	Program Manager	1	104,940	x		Not yet filled	X - DSM	Program Development and Administration due to growth of the program — adding staff to perform market segmentation, procurement and contract administration, and evaluation measurement and verification.
Customer Service	ROW Agent	4	326,996		x	Not yet filled		Centralize RoW function through dedicated agents throughout our KU territory.
Customer Service	Supervisor Facility Operations	1	183,670		x	Not yet filled		This position will oversee the Company’s lease agreement with building owner to ensure all lease provisions are properly executed and terms and conditions of the lease are fulfilled at the corporate facility.
Customer Service	Meter Reader (transfer from Green River plant)	11	712,426		x	Not yet filled		As a result of the Green River plant closure slated for 2015, Customer Services has agreed to absorb up to 13 positions within meter reading. These positions would offset current meter reading contractors located in Western Kentucky. Agreement called “The Letter of Understanding” that was a part of the 2014 contract with the United Steelworkers. At the time of the agreement, there were 11 contractors performing this function.
Gas Distribution	Gas Controller	1	85,947	x		Not yet filled		Position is budgeted for hire in August 2014 to allow 12 months overlap for new employee and anticipated retiree; As a result of the Control Room Management regulations, most companies have added incremental Gas Controller positions to avoid single person operation of the Gas Control Center.
Gas Distribution	Auxiliary Operator	1	56,465	x		Not yet filled		Position is needed to reduce the risk of not being able to provide treated natural gas to the distribution system that meets or exceeds regulatory requirements.
Gas Distribution	Gas Analyst	1	69,760		x	Not yet filled		GDO does not currently have analyst positions within the operating groups. This position would have the primary responsibilities for metrics, benchmarking efforts and communications.

Department	Position	No. of positions	Payroll expense $	Base year	Test year	Status of 3/31/15	Mechanism Related	Justification of positions not yet filled
Gas Distribution	Distribution Mechanic	1	55,862		x	Not yet filled		Budgeted for hire in January 2016; Over the next 5 years there are 15 employees that will be retirement eligible representing over 300 years of gas knowledge and experience. There is significant concern over the loss of this experience from the field.
Gas Distribution	Gas Controller	1	92,650		x	Not yet filled		Position isn't budgeted for hire until May 2016 to allow 12 months overlap for new employee and anticipated retiree; As a result of the Control Room Management regulations, most companies have added incremental Gas Controller positions to avoid single person operation of the Gas Control Center.
Gas Distribution	SR&O Technician	1	47,359		x	Not yet filled		Position is budgeted for hire in April 2015 to allow 6 months overlap for new employee and anticipated retiree;
Generation	E&I Technician	1	79,469	x		Not yet filled	X	Instrumentation & controls maintenance related to addition of new technologies and equipment. CCP, FGD.
Generation	Electrical Engineer	1	193,364	x		Not yet filled	X	Post Jet Fabric Filter (Bag House) Projects
Generation	Fuels Analyst	1	112,172	x		Not yet filled		Prefill for retirement
Generation	Material Handling Leader	1	100,487	x		Not yet filled		Provide in-house leadership, oversight, and LOTO activities for increasingly variable material handling workforce.
Generation	Mechanic	1	154,062	x		Not yet filled	X	Mechanical maintenance technical support related to addition of new technologies and equipment. PJFF, CCR, and sorbent injection systems.
Generation	Electrical Engineer	1	96,682		x	Not yet filled		Performance monitoring and VISTA management
Generation	CCR Supervisor	1	118,127		x	Not yet filled	X	Regulatory Compliance oversight for CCR transport and all associated porcesses
Information Technology	Programmer Analyst	1	415,535	x		Not yet filled		Expanded use and enhancement of Financial Systems and Quest applications.
Electric Distribution	Engineer Design Tech (Danville)	1	72,485	x		Not yet filled - on hold		Position on hold because aniticipated retirement was postponed
Electric Distribution	Line Technicians (Louisville)	1	62,540		x	Not yet filled - on hold		Position on hold because it is anticipated there will be more openings due to promotions and will fill once those have been completed
Customer Service	Meter Tech retirement	-1	(73,199)	x		Not yet occurred		
Electric Distribution	Substation Tech retirement	-1	(80,327)	x		Not yet occurred		
Gas Distribution	SR&O Technician retirement	-2	(159,496)		x	Not yet occurred		
Gas Distribution	Distribution Mechanic retirement	-1	(81,181)		x	Not yet occurred		
Gas Distribution	Gas Controller retirement	-1	(100,972)		x	Not yet occurred		
Generation	Fuels Analyst Retirement	-1	(89,925)		x	Not yet occurred		
Generation	Cane run plant retirements	-25	(2,203,555)		x	Not yet occurred		
Generation	Green River plant retirements	-15	(1,322,063)		x	Not yet occurred		
Generation	Green River transfer to metering	-11	(712,426)		x	Not yet occurred		
Safety and Technical Training	Training Consultant retirement	-1	(94,347)	x		Not yet occurred		
Safety and Technical Training	Health and Safety Coordinator	-1	(107,627)		x	Not yet occurred		
Gas Distribution	Storage Operator retirement	-1	(81,467)	x		Retirement Occurred		
Gas Distribution	Trouble Technician retirement	-1	(79,748)	x		Retirement Occurred		
Generation	Operator - hrly -retirement	-1	(81,941)	x		Retirement Occurred		
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72 Positions have been filled (3 ADMIN, 10 CS, 22 EDO, 1 GDO, 19 GEN, 12 IT, 5 TRANS)
40 Positions have an active posting or pending start date. Active Posting - 28 (1 ADMIN, 1 CS, 3 EDO, 11 GDO, 5 GEN, 4 IT, 2 SAFETY, 1 TRANS), Pending Start Date-12 (1 CS, 3 EDO, 5 GDO, 1 GEN, 1 IT, 1 TRANS)
43 Positions are not yet filled (1 ADMIN, 26 CS, 6 GDO, 7 GEN, 1 IT, the 2 EDO positions are on hold)
(60) Retirements/transfers have not yet occurred (-1 CS, -1 EDO, -4 GDO, -52 GEN, -2 SAFETY)
(3) Retirements Occurred (2 GDO, 1 GEN)
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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2014-00371**

In Re the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

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

Dated: April 14, 2015

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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. As Treasurer for the Companies, I am responsible for the Companies' relationships with rating agencies and banks. In addition, I have certain oversight responsibilities in connection with the Companies' retirement plans.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to certain of the arguments presented in the testimony of Mr. Frank W. Radigan and Dr. J. Randall Woolridge on behalf of the Attorney General ("AG"), and Mr. Lane Kollen and Mr. Richard Baudino on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"). Specifically, I will address questions relating to the Companies' defined benefit retirement plans, the cost of long and short term debt as well as the Companies' capital structure.

The Companies' Defined Benefit Retirement Plans

Q. Briefly explain the AG's and KIUC's arguments with regard to the Companies' defined benefit retirement plans.

A. Mr. Radigan questions the use of the RP-2014 Mortality Table ("2014 Mortality Table") since it has not yet been formally adopted by the IRS. He also questions certain assumptions made by the Companies, and the Companies' methodology for amortizing actuarial gains and losses. He claims that since the Companies' assumptions deal with issues that are not known and measurable, forecasted data should not be used. Mr. Kollen also criticized the size of the Companies' pension expense increase from 2014, lowering of the discount rate used to compute the Companies' projected benefit obligations, as well as the period used to amortize the actuarial loss, and suggested that a 30 year amortization be used instead.

Q. What would be the impact of the changes they suggest?

A. Mr. Radigan would reduce the Companies' pension expenses to the "known and measureable 2014 booked" expenses, or a reduction in KU's revenue requirement of $15,316,122, and a reduction of $16,659,336 for LG&E. Mr. Kollen would reduce KU's pension expense by $10,682,000 and LG&E's electric expense by $12,627,000.

Q. Is it appropriate to look only at the increase in pension expense since 2014 as Mr. Radigan and Mr. Kollen propose?

A. No. As discussed in Mr. Kent Blake's Rebuttal Testimony, the pension expense included in the Companies' forward-looking test period in this proceeding should be compared to the pension expense the Companies have experienced in the past, and the expense that was included in the Companies' last base rate cases. Mr. Blake's testimony shows that the LG&E pension expense embedded in current rates is slightly higher than the projected test year costs while KU's expense is somewhat higher mostly due to a change in the capitalization rate for labor and a change in the jurisdictional factor.

Q. Is the criticism of the Companies' use of the 2014 Morality Table valid?

A. No. As noted in response to the AG's Initial Data Request No. 15, Accounting Standards Codification ("ASC") 715, *Compensation – Retirement Benefits*, at ASC 715-30-35-42, states that when measuring a plan's defined benefit obligation and recording the net periodic benefit cost, "each significant assumption used shall reflect the best estimate solely with respect to that individual assumption." As also stated in that Data Response, the SEC, through a Professional Accounting Fellow with the Office of Chief Accountant has stated that “the [SEC] staff does not believe it would be appropriate for a registrant to disregard the … new mortality data in determining their best estimate of mortality.” The Companies’ auditor, Ernst & Young LLP, as well the Deloitte & Touche LLP accounting firm, have advised plan sponsors to consider whether they should use the 2014 Mortality Table. This advice is discussed in greater detail in the response to KIUC Data Request 2-3. Recently, Towers Watson, the Companies’ actuary, provided the results of a year-end 2014 survey of the mortality tables used by its clients. 87% of 131 Towers’ clients and 88% of its 34 regulated utility clients included in the study have moved to some form of the 2014 Mortality Table. See Rebuttal Exhibits DKA-1. In addition, attached to this testimony as Rebuttal Exhibit DKA-2 is the Demographic Experience Study performed by Towers Watson during the fourth quarter of 2014 specifically for the Companies’ plans. This study confirmed that the 2014 Mortality Table matched the Companies’ experience more closely than other alternative tables. However, the deviation between the projected experience based on the 2014 Mortality Table and our actual experience caused the Companies to reduce slightly the longevity suggested by 2014 Mortality Table as described in the response to KIUC 2-3. The impact of this adjustment was to reduce the projected benefit obligation and corresponding pension expense otherwise associated with use of the 2014 Mortality Table. The timing of the IRS’ adoption of the 2014 Mortality Table was not, and should not be, a factor in determining whether to use the updated table. The IRS approved rate is used solely for determining pension funding requirements under ERISA, and the IRS is only required to update it every ten years.

Q. Should the future projected pension obligations be disregarded as “speculative”?

A. Of course not. First of all, pension costs are by their nature projections. One must always make assumptions such as what percentage of employees will stay long enough to qualify for a pension, at what age will those employees retire, and how long will they live after retirement. Furthermore, the Companies did, in fact, use the adjusted 2014 Mortality Table to determine the year-end 2014 projected benefit obligation and are using the result to calculate actual 2015 pension expense. Mr. Radigan's claim that these costs are not "known and measurable" ignores the fact that Case Nos. 2014-00371 and 2014-00372 are based on a Forecasted Test Period, and not on a Historical Period. In 1992, the General Assembly adopted KRS 278.192, which specifically allows utilities to use a forward looking test period in rate cases. Since that time, the Commission has adjudicated many cases involving forecasted test periods..

Q. Have the Companies altered the discount rate used to determine the projected benefit obligation in order to manipulate their pension expense?

A. No. The projected benefit obligation is a measurement of the present value of future pension benefits at a point in time. The interest rate used to discount the future benefit payments back to the present is determined by creating a hypothetical portfolio of actual AA rated bonds whose cash inflows match the projected benefit payment outflows. Market interest rates declined significantly throughout 2014. When the initial projections of 2015 pension expense were prepared in May 2014, interest rates were approximately 50 basis points (bps) below year-end 2013 levels and the projections assumed no further decline in interest rates for the remainder of 2014. However, by the end of 2014, interest rates had declined even further, and the year-end discount rate reflected in the updated February projections declined by 93 bps from year-end 2013. ASC 715-30-35-44 states, "If the general level of interest rates rises or declines, the assumed discount rates shall change in a similar manner." The Companies were not manipulating the discount rate, but were simply complying with the calculation methodology required by GAAP.

Q. Please explain the Companies' method for amortizing unrecognized actuarial gains and losses.

A. Prior to 2010, the net unrecognized gains or losses in excess of 10% of the greater of the plan's projected benefit obligation or market-related value of plan assets were amortized on a straight–line basis over the estimated average future service period of plan participants (currently slightly less than nine years). Under our current accounting method, a second amortization rate is utilized for net unrecognized gains or losses in excess of 30% of the plan's projected benefit obligations. The net unrecognized gains or losses outside this second threshold are amortized on a straight–line basis over a period equal to one-half of the average future service period of the plan participants. This current method was used in the Companies' prior base rate cases (Case Nos. 2012-00221 and 2012-00222) and has been noted in our financial statements filed with the Commission since 2010. This method is preferable because it provides more current recognition of gains and losses, thereby lessening the accumulation of unrecognized gains or losses.

Q. Why is this preferable?

A. The Companies' defined benefit retirement plans were closed to new employees beginning in 2006. For new employees after that date, the Companies provide only defined contribution plans. The accumulated actuarial losses under the defined benefit plans relate to services that have previously been provided or will be provided by those employees and retirees covered under the now closed defined benefit plans. The more rapid recovery of those actuarial loses minimizes the cross generational impact of future customers having to pay the retirement benefit costs for employees who provided services for the benefit of past customers. A longer amortization period is particularly inequitable if you consider that as the Companies transition to defined contribution plans, those future customers will have to pay not only the costs associated with past employee services, but current employee benefit costs as well.

Q. What is the revenue impact of using the revised methodology to amortize gains and losses?

A. For LG&E, the revised approach increases the revenue requirement by approximately $1.1 million and for KU by $400,000. These amounts are relatively minor because the 30% amortization applies only to the small portion of the losses in excess of 30% of the projected benefit obligation.

Q. Were the Companies required to obtain the Commission's approval for this change?

A. No. The Commission has previously held that utilities under its jurisdiction do not require prior approval for accounting changes.[1]

Q. Mr. Kollen has recommended that the actuarial loss be amortized over a 30 year period. Is this reasonable?

A. No. Mr. Kollen speculates that because some plan participants may continue drawing benefits for 60 years or more, it is reasonable to amortize over a 30 year period, which represents approximately one half of that life expectancy. However, in response to LG&E and KU Data Request 1-19, Mr. Kollen admits he knows of no company using such a

[1] *See, e.g., In the Matter of: The Joint Petition of Kentucky Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, and Union Light, Heat and Power Company for Certain Accounting and Ratemaking Authority Associated with the Implementation of Statement of Financial Accounting Standards No. 106,* Case No. 92-043, Order at 3-4 (June 8, 1992; Jan.26, 1993).

lengthy amortization period for pension expense. ASC 715-35-24 states, "If amortization is required, the minimum amortization shall be that excess (above 10% of the projected benefit obligation) divided by the average remaining service period of active employees expected to receive benefits under the plan." In addition, such an unreasonably long amortization period significantly increases the intergenerational transfer problem discussed above.

Q. In response to the Companies' Data Request 1-4, Mr. Kollen also suggests that increasing the amortization period would not harm the Companies. Is that accurate?

A. No. In addition to the unfair burden on future customers, this approach of deferring the costs by more than tripling the current amortization period would directly impact the Companies. The most important financial ratios monitored by the rating agencies are all cash flow metrics. Deferring the cash recovery of these costs would impair these important financial metrics.

Q. Do the pension adjustment calculations provided by AG witness Radigan and KIUC witness Kollen contain any errors?

A. Yes. AG witness Radigan's pension expense adjustment calculations for the KU and LG&E revenue requirement reflects "total cost," including capital and O&M cost components. The Companies' data responses did not separate the cost components between capital and O&M, but are provided as Rebuttal Exhibit DKA-3. The recommended pension adjustments require the application of O&M allocation ratios. In addition, the AG witness Radigan's calculation of the LG&E pension expense adjustment incorrectly applies a 75/25 ratio to the electric/gas expense. The correct ratio is 79/21.

KIUC witness Kollen's pension expense adjustment calculations for KU and LG&E reflect "total cost" including capital and O&M cost components. The Companies' data responses did not separate the cost components between capital and O&M. The KIUC pension expense adjustment calculations require the application of the O&M allocation ratios.

Q. Do the Companies anticipate receiving updated information concerning their pension expense?

A. Yes. Towers Watson is expected to provide us with final 2015 pension expenses in mid-April which will be an update to the February estimates previously provided in the data responses to KPSC 3-9 for LG&E and KPSC 3-5 for KU. This update will reflect only the demographic variances from the expectations (i.e., the actual number of people retired or passed away in 2014) used in the calculation. Accordingly, the update is expected to reflect only a small change. We will provide this information as soon as it is received.

Cost of Long Term Debt.

Q. Mr. Baudino and Mr. Kollen propose reducing the interest rate on long-term debt that the Companies plan to issue late in 2015. Is this reasonable?

A. No. Mr. Baudino proposed and Mr. Kollen agrees that the interest rate on a total of $550 million of long term debt that LG&E plans to issue and a total of $500 million of long term debt that KU plans to issue be lowered to 3.70%. This proposal is based on interest rates as of February 27, 2015, not on expected interest rates at the time of issue, and ignores the fact that between July 2014 and October 2014 the Companies entered into forward starting interest rate swaps that locked in the treasury rate component on these future issuances at 2.86% for the portion of this debt that the Companies will issue with 10 year terms, and 3.31% for that portion of the debt that will be issued with 30 year terms. The interest rates proposed by the Companies (3.89% for the 10 year portion and 4.38% for the 30 year portion) reflect the interest rate swaps in place as of mid-September 2014 and forward interest rates for the unhedged portion plus the credit spreads as of September 12, 2014.

Q. Why did the Companies seek to lock-in their interest rates prior to issuance?

A. The most important purpose was to protect the Companies and their customers from volatility in the credit markets. The general consensus in the credit markets when the Companies entered into these swaps was that long-term interest rates would rise as the economy continued to improve, and as the Federal Reserve eliminated quantitative easing measures, and took actions to increase the Federal Funds Rate. These interest rate swaps protect the Companies and their customers from the impact of such increases. Moreover, the interest rates that the Companies were able to lock in compare very favorably with the rates for similar debt that the Companies have issued in recent years. For example, in November 2013, both LG&E and KU issued 30 year bonds at 4.65%. Over the last 20 years 10-year treasuries have been higher than the rates the Companies have locked in approximately 80% of the time and 30-year treasuries have been higher approximately 87% of the time.

Q. Have the Companies used interest rate hedges in connection with long term debt issuance previously?

A. Yes. The Companies routinely seek authority to issue new long term debt under KRS 278.300, and request authority to enter into swaps or other interest rate hedges to protect both the Companies and their customers from the effects of rising interest rates. In both Case No. 2014-00082 (KU) and Case No. 2014-00089 (LG&E), in which the planned 2015 long-term debt was authorized, the Companies requested and received such authority from the Commission. The Companies effectively used such hedges to keep their long term debt costs low in Case No. 2012-00232 (KU) and Case No. 2012-00233 (LG&E).

Q. How does the cost of the Companies' debt compare to that of comparable utilities?

A. Attached to their Applications as Exhibit KWB-7 was a survey of other utilities in the Companies' peer group showing that LG&E had the lowest and KU the second lowest cost of debt among the companies surveyed, which continues to be the case. Attached to my testimony as Rebuttal Exhibit DKA-4, is a similar survey for the 12 months ending December 2014, again showing that LG&E has the lowest and KU the second lowest cost of debt.

Short Term Debt

Q. What adjustments to the Companies' cost of short term debt did Mr. Kollen propose?

A. The Companies had proposed a cost of short term debt of 0.636% for the July 2015 through December 2015 portion of the test year and a rate of 1.585% for the January 2016 through June 2016 portion of the test year resulting in a blended rate of 0.905%. Mr. Kollen proposed to reduce the short term rate to 0.30%, for a reduction in KU's revenue requirement of $0.645 million and a reduction of $0.561 million for LG&E.

Q. Are Mr. Kollen's proposed short term interest rates reasonable?

A. No. Mr. Kollen ignores the fact that the rates proposed by the Companies are not for commercial paper issued today, but at various times in the future. The Federal Reserve is clearly messaging to the market that it will commence raising short-term interest rates during 2015 and has removed the language stating that it will be "patient" in waiting for labor markets to improve. Most economists are now projecting that the Federal Reserve will take steps to raise rates before the end of 2015. Furthermore, the rates Mr. Kollen cites are for commercial paper issued by AA rated financial institutions, and are not applicable to the Companies. Rebuttal Exhibit DKA-5 is a reproduction of a web page published by the Federal Reserve showing commercial paper rates as of March 31, 2015. The exhibit shows that AA rated financial institutions have been able to issue 90 day paper at an average rate of .15% during 2015. More importantly, it shows that A2/P2 nonfinancial issuers such as the Companies have had to pay .52% year-to-date. Even before any action on the part of the Federal Reserve, the applicable commercial paper rates are within .12% of what was assumed in the filing for the second half of 2015. In addition, the quoted index rates do not include the dealer fees embedded in the interest rate that the Companies pay which average 5 bps (.05%).

Capital Structure

Q. Dr. Woolridge has recommended that the Companies' capital structure be reduced to 50.0% common equity. Is this advisable?

A. No it is not. As I noted previously, LG&E and KU have the lowest costs of debt among all the utilities in their comparison group. One reason for their low costs of debt is that the Companies are not over-leveraged. As discussed in Mr. Blake's Direct Testimony, the ratings agencies consider the Companies' ability to meet their debt obligations as they are due when ratings are assigned, which directly affects the cost of debt. In addition, keeping their level of debt reasonable means that the Companies will have the capacity to raise funds through debt in the future at reasonable costs, a critical issue in light of the prospect of increasing regulatory and environmental obligations. The appropriateness of the Companies' capital structure and its importance in ensuring continuous access to capital needed to fund operations and necessary system investment is discussed more fully in the rebuttal testimony of Mr. Avera and Mr. McKenzie.

Q. Dr. Woolridge also notes that the Companies' parent, PPL has a higher level of debt than the Companies. Is this relevant?

A. No. PPL is a public utility holding company, not itself a regulated utility. The financial statements of PPL Corporation are consolidated statements for all of its subsidiaries. These subsidiaries include a range of companies with a range of risk profiles.. As discussed more fully by Mr. Avera and Mr. McKenzie in their rebuttal testimony, the Companies' equity ratios in fact fall within the capitalization range of the utility proxy group used by both Mr. Avera and Mr. McKenzie and by Dr. Woolridge to estimate their cost of equity. This Commission has long recognized the importance of LG&E and KU maintaining their ability to access the capital markets and raise funds independent of their parent. In the most recent merger case, Case No. 2010-00204, the Commission, in Appendix C to the September 30, 2010 Order approving PPL's acquisition of LG&E and KU, required the Companies to "each maintain its own corporate credit rating as well as ratings for long-term debt from Moody's and S&P or their successor rating agencies." This Order recognizes that the Companies' ratings, although possibly affected by factors within the holding company, must still be independently assessed. Additionally, Section 3.1 of Appendix A to the September 30, 2010 Order provides "PPL acknowledges that attempts to alter LG&E's and KU's capital structures could adversely affect the utilities' cost of capital and financial integrity; therefore PPL will assist LG&E and KU in maintaining balanced capital structures." LG&E's proposed 52.75% common equity and KU's proposed 53.03% common equity, are both within the historic range of the Companies' "balanced capital structure", which the Companies are committed to maintain.

Q. Did Mr. Radigan correctly calculate the revenue requirement impacts of his proposed capital structure and interest rate changes?

A. No. Mr. Radigan's recommended changes to the revenue requirement resulting from capital structure and interest rate changes do not reflect the interest synchronization adjustment. He failed to adjust the income tax expense to reflect the changes to capitalization and interest rates.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
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 10th day of April 2015.

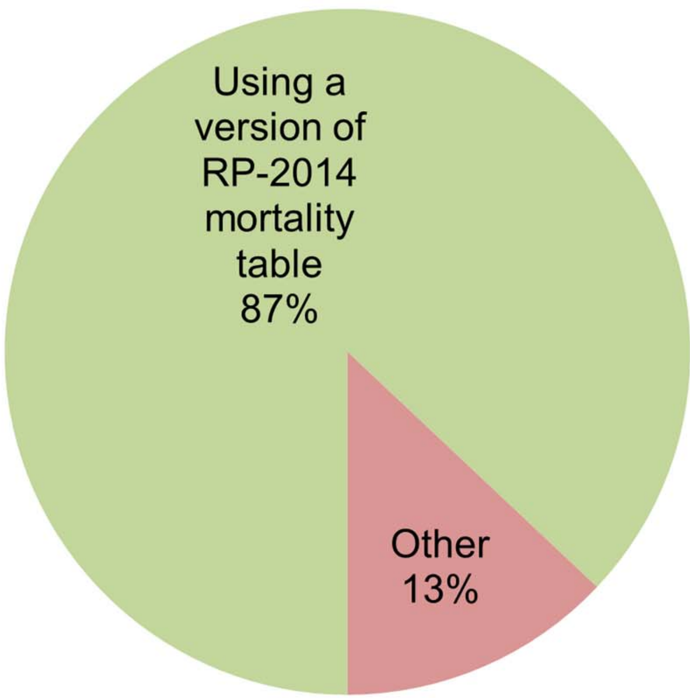
Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

Towers Watson Mortality Assumption Survey Data

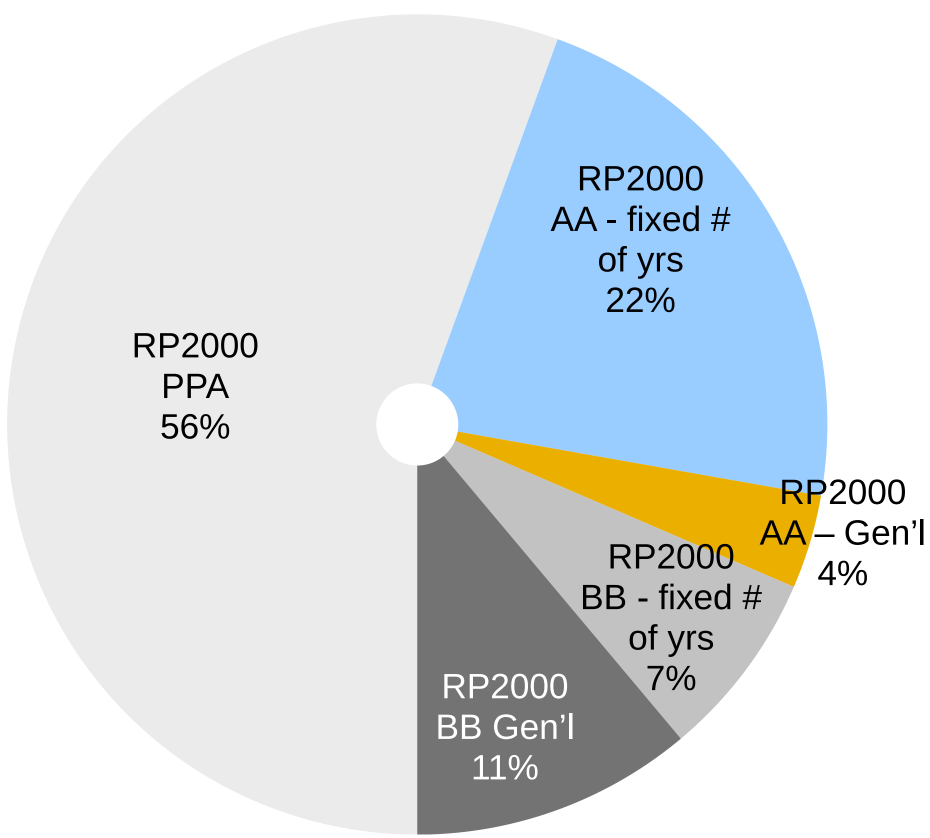
- The following chart shows the prevalence of RP-2014 base table adoption by plan sponsors for 12/31/2014 fiscal year-end reporting
  - Includes sponsors who modified the RP-2014 base table to reflect actual plan experience
  - Does not differentiate by mortality improvement scale adopted (e.g., MP-2014, MP-2014 adjusted, Scale BB-2D, etc.)
- These results are from an internal Towers Watson survey completed during the first quarter of 2015, and includes 131 Towers Watson clients



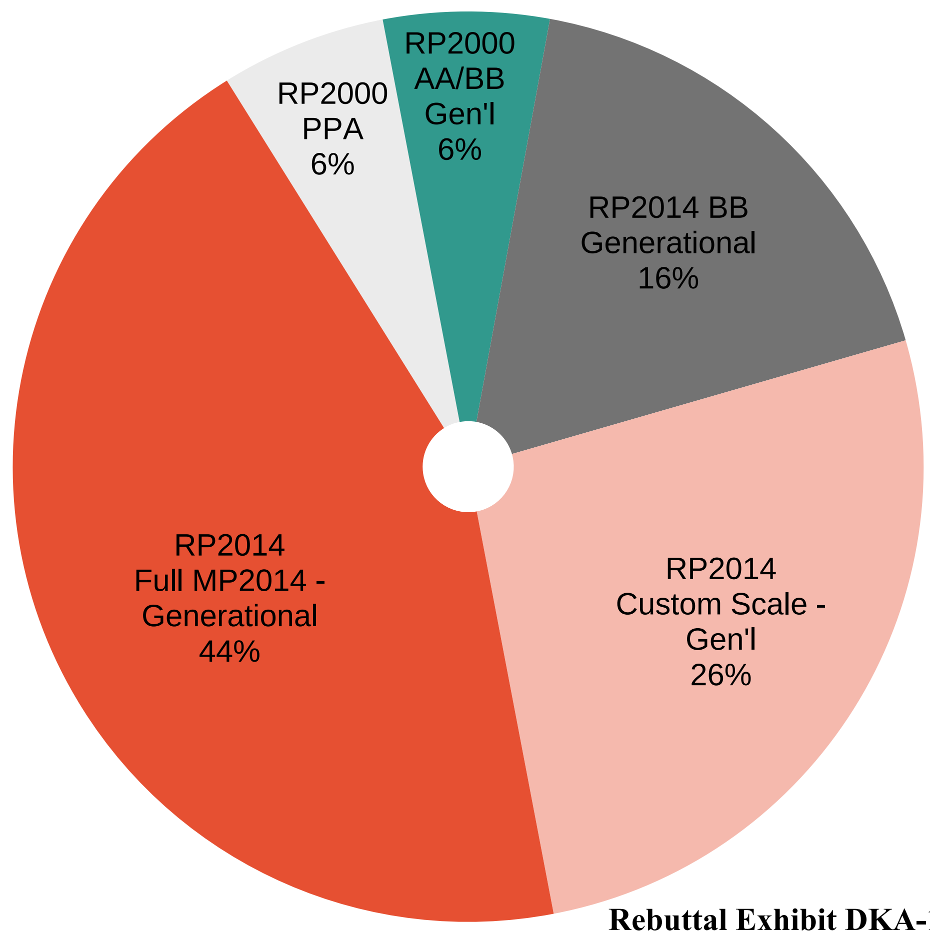
PPL Corporation
Towers Watson - Mortality Assumption Survey

- We conducted an informal survey of regulated utility clients at Towers Watson
- 34 responses for FYE 2014 assumption and 27 responses for FYE 2013 assumption

FYE 2013 Assumption



FYE 2014 Assumption



Rebuttal Exhibit DKA-1
Page 2 of 3

PPL Corporation
Towers Watson - Mortality Assumption Survey (continued)

Prior Year Mortality Assumption
· PPA – 15 (56%)
· RP2000 with AA scale for fixed # of years – 6 (22%)
· RP2000 with AA scale generational – 1 (4%)
· RP2000 with BB scale for fixed # of years – 2 (7%)
· RP2000 with BB scale generational – 3 (11%)

Expected Current Year Mortality Assumption
· RP2014 with full MP2014 – 15 (44%)
· RP2014 adjusted for experience with custom projection scale – 6 (18%)
Example: RP2014 with 107% multiplier adjustment and projection scale converging to long term 0.75% improvement over 5 year period
· RP2014 with BB scale generational – 5 (15%)
· RP2014 adjusted for experience with BB scale generational – 1 (3%)
· RP2014 with custom projection scale – 3 (9%)
· RP2000 PPA – 2 (6%)
· RP2000 with AA scale generational – 1 (3%)
· RP2000 with BB scale generational – 1 (3%)

For FYE 2014

- ***Base Table:*** 30 (88%) selected RP2014; 7 adjusted for experience
- ***Approach:*** Over 90% are adopting generational approach
- ***Projection:*** 15 (44%) are adopting full MP2014 with no adjustments

PPL Corporation

2014 Experience Study and Demographic Assumptions Review

A presentation to PPL and LKE
by Jennifer Della Pietra, Royce Kosoff and Kristin May

TOWERS WATSON

November 12, 2014

Meeting purpose

- Assumption setting is a joint effort between PPL, LKE and Towers Watson
  - PPL and LKE have the responsibility for selecting assumptions that affect the Company's financials including retirement benefit costs and liabilities recorded in financial statements
  - Towers Watson actuaries have the professional responsibility for appropriateness of suggested assumptions (necessary to fulfill role of specialist to be relied upon for choice of assumptions)

- This meeting is intended to support discussion regarding the appropriate demographic assumptions to be used for year-end 2014 financial reporting of benefit plans and fiscal 2015 benefit costs
  - PPL and LKE review economic and demographic assumptions annually
  - A detailed demographic experience study is performed every 3 years

<u>Primary objective of the study</u>

To continue to harmonize assumptions across PPL and LKE where appropriate, while acknowledging that certain assumptions will continue to differ due to actual experience and program design differences

Meeting agenda

1. **Demographic assumptions**
   - Overview and high level summary
   - Mortality
   - Retirement
   - Termination
   - Compensation increase rate
   - Secondary demographic assumptions
   - Summary
2. **Next steps**
3. **Appendix**
   - Actuarial certification
   - Supplemental assumption information

Overview

- Liability losses and gains are generated when actual demographic experience differs from the selected demographic assumptions
- Key demographic assumptions include mortality, retirement, termination, compensation increase
- PPL and LKE have mitigated unexpected obligation changes by completing timely reviews and updates of demographic assumptions (three-year experience study cycle)

	Impact on PBO Attributable to Unexpected Demographic Changes			
($ millions)	PPL Retirement Plan		Total LKE Qualified Plans	
Fiscal Year End	**$ change**	**% change**	**$ change**	**% change**
2013	$ 16.9	0.44%	$ - 8.8	-0.70%
2012	$ 13.8	0.47%		
2011	$ 28.2	1.05%		
2010*	$ 26.6	1.11%		
2009**	$ 1.9	0.09%		
2008	$ 14.7	0.67%		
2007	$ 0.8	0.04%		

* Fiscal year-end 2010 impact includes updates from Fidelity transition
** Fiscal year-end 2009 impact includes update to reflect target bonus percentage

Demographic experience study: High level summary

- Three years of PPL and LKE experience was reviewed to determine the appropriateness of the current demographic assumptions for the plans (for mortality, longer period was used if available and appropriate)
- The assumptions were reviewed for the following:

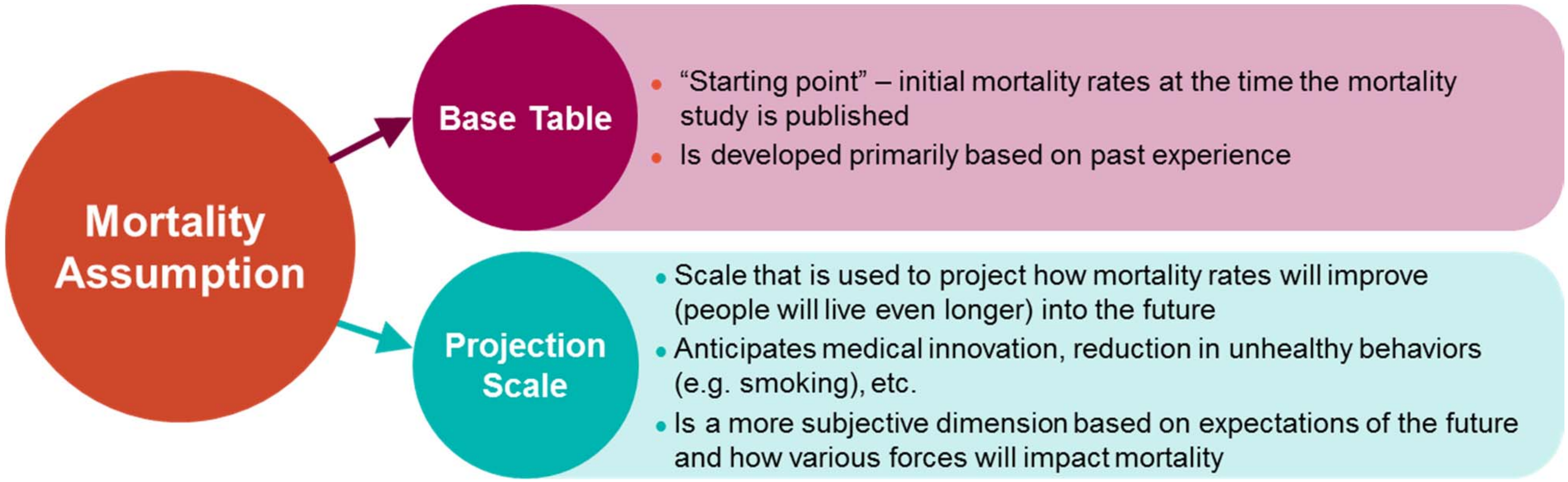
Comparability to historical plan experience	Expected future experience (if different than past experience)	Consistency among the plans, or ability to explain differences

- Based on the results of the study, preliminary considerations for the plans are as follows:
  - Mortality: Update to RP-2014 with possible adjustments:
    - Collar: No collar vs Blue /White adjustments
    - Further rate adjustments to reflect PPL/LKE experience
  - Retirement: Consider updating retirement rates at specific ages for both PPL and LKE
  - Termination
    - PPL: Retain current “select and ultimate” assumption and monitor experience
    - LKE: Change basis to SOA Hourly Union Termination Table for non-union and union plans with adjustment (2x table) for union plan
  - Compensation Increase:
    - PPL: Decrease assumption by 0.5% for ages 29 through 39, decrease assumption by 0.5%.
    - LKE: Decrease flat rate assumption by 0.5% and reflect separate assumption for SERP

Mortality

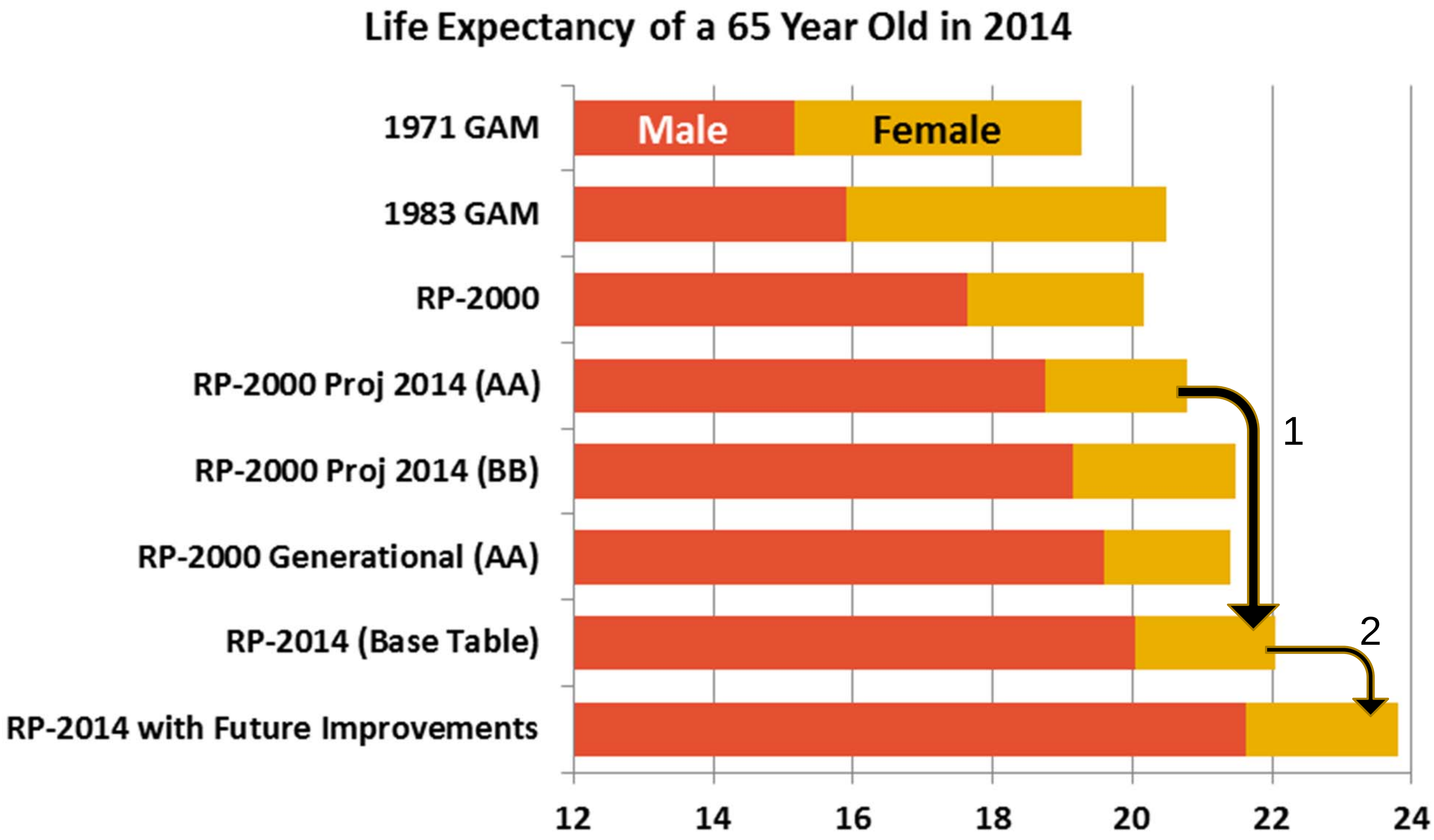
Mortality overview

- Plan cost must be calculated using assumptions reflecting PPL's best estimate of future experience related to that assumption
- A mortality assumption is composed of two parts:



- PPL and LKE experience was reviewed using Towers Watson's credibility tool to help determine if a version of the RP-2014 base table is an appropriate fit to plan experience, and if so, which version/variations should be used
- PPL and LKE will also need to determine if the MP-2014 mortality improvement projection scale is appropriate, though there is not enough plan specific data to test the scale in the same manner as the base table

Mortality: Life Expectancy Overview



Mortality Credibility Analysis

- We have reviewed actual mortality experience for retirees and surviving spouses in the PPL and LKE qualified pension plans on a combined basis and split by plan, where appropriate
- Benefits weighting of mortality experience
  - Approach is intended to be a proxy for weighting mortality rates by liability
  - Reflects liability that is expected to be released due to mortality, acknowledging that higher benefit levels are correlated with longer life expectancies
  - Published pension mortality tables (e.g. GAR-94, RP-2000 and RP-2014) were developed using benefit amounts rather than lives
- Actual experience was compared to expected experience based on the following standard mortality tables:
  - Current mortality assumption of the plans (not shown)
  - RP-2014 mortality table, with no collar adjustments, with improvement projections under MP-2014 (projected to the midpoint of the data)
  - RP-2014 mortality table, with white collar adjustments, with improvement projections under MP-2014 (projected to the midpoint of the data)
  - RP-2014 mortality table, with blue collar adjustments, with improvement projections under MP-2014 (projected to the midpoint of the data)

Mortality Experience Analysis: Approach to adjusting standard tables to reflect plan credibility

- Given the large amount of data that is needed to develop a fully credible mortality table, only a few of the largest pension plans in the world would have sufficient data to build their own tables
- A more practical approach is to adjust a standard mortality table up or down (i.e., apply mortality rates that are a +/- x % of the standard table) based on the deaths experienced by the plan over a number of years
  - A fundamental premise to this approach is that the underlying shape of the standard table is appropriate and that a consistent adjustment can be applied at all ages based on plan specific experience
- The larger the amount of experience data available, the greater the credibility that can be assigned to the analysis of past experience
  - To the extent that full credibility is not realized, the recommended table is created by a weighted-average of the standard table and the adjusted table using the level of credibility
  - For example, if the adjustment factor determined by the study is 10% and the results are 30% credible, then a reasonable adjustment factor will be 3.0%
- Results on following slides reflect a +/-5% level of accuracy with a 90% confidence level
  - i.e., there is a 90% probability of being within 5% of the true value

Mortality Credibility Analysis
PPL + LKE Experience vs. Various Base Tables

- Actual deaths (benefits-weighted) for all combined plans are higher than expected based on the RP-2014 white collar table and lower than expected based on the RP-2014 no collar table (i.e. retiree death rates are higher than the white collar rates)
  - Current assumption shown for illustrative purposes only
- The resulting adjustment factor to be applied to the standard mortality rates, after reflecting the credibility factor, is +10.7% for the white collar table and -5.2% for the no collar table

PPL (3 years of data) + LKE (3 years of Data)	RP-2000 Current assumption	RP-2014, White Collar	RP-2014, No Collar
Total Records (Life-Years)	27,433	27,433	27,433
Actual Number of Deaths	821	821	821
Actual/Expected Deaths (A)	.836	1.151	0.919
Credibility Factor (B) Results reflect a level of accuracy of +/-5% with a 90% confidence level	0.612	0.706	0.637
Resulting Adjustment Factor 1+[(A) – 1] x (B) To Be Applied to Standard Mortality Rates	90.0%	110.7%	94.8%

- While selection of a single table (as illustrated above) would enable continued harmonization of this assumption, a better fit by company may be available (next pages)

Mortality Credibility Analysis
PPL Experience vs. Various Base Tables

- Results below reflect PPL Retirement Plan and PPL Subsidiary Plan mortality experience
- Experience is split between non-union and union employees
- Actual deaths for non-union population most closely align with the white collar table*
  - Adjusted non-union retiree death rates are 2.2% (100% minus 97.8%) lower than white collar rates
- Actual deaths for union population most closely align with the no collar table
  - Adjusted union retiree death rates are 0.6% (100% minus 99.4%) lower than no collar rates

	Non-union		Union
PPL (7 years of data)	**RP-2014, White Collar***	**RP-2014, No Collar**	**RP-2014, No Collar**
Total Records (Life-Years)	20,028	20,028	15,668
Actual Number of Deaths	527	527	462
Actual/Expected Deaths (A)	0.958	0.774	0.990
Credibility Factor (B) Results reflect a level of accuracy of +/-5% with a 90% confidence level	0.528	0.475	0.567
Resulting Adjustment Factor 1+[(A) – 1] x (B) To Be Applied to Standard Mortality Rates	97.8%	89.3%	99.4%

* Note that the RPEC study also analyzed mortality data based on annual salary for actives and annual benefit amount for retirees. RP-2014 Top Quartile table reflects experience for males (> $25,000 annual benefit) and females (> $14,000 annual benefit). When matched against PPL non-union experience above, the result was within 1% of the adjustment factor applicable to the white collar table.

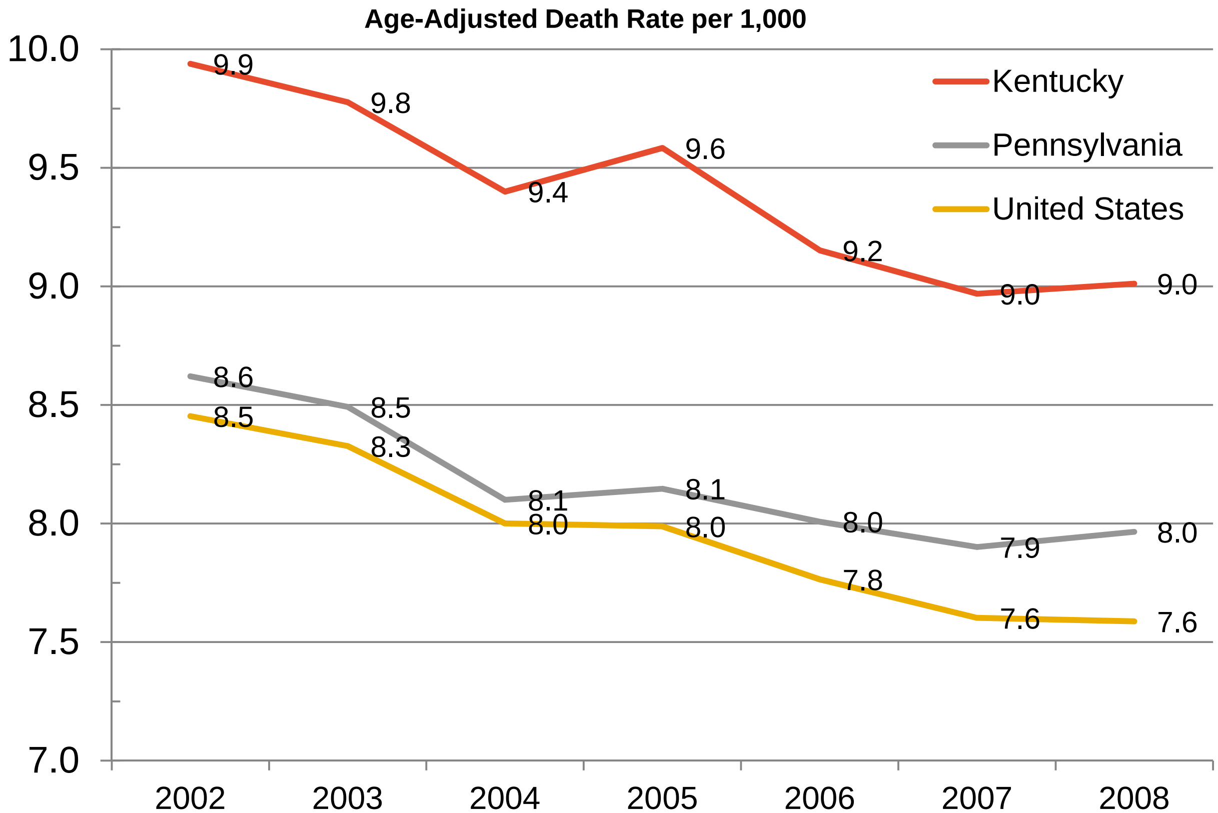
Mortality Credibility Analysis
LKE Experience vs. Various Base Tables

- Results below reflect LKE non-union plan and LKE union plan mortality experience
- Actual deaths for non-union population align equally well with the white collar table and the no collar table
  - Adjusted non-union retiree death rates are 3.3% higher than the white collar rates and 3.2% lower than the no collar rates
- Blue collar table a better fit for union experience, though rates are 8% higher than table
- If it is decided to use separate tables across the company, LKE could consider adjustment to blue collar table to reflect union experience - factor to be applied to the standard mortality rates, after reflecting the credibility factor, would be +8.0%

	Non-union		Union	
LKE (3 years of data)	**RP-2014, White Collar**	**RP-2014, No Collar**	**RP-2014, No Collar**	**RP-2014, Blue Collar**
Total Records (Life-Years)	6,857	6,857	4,675	4,675
Actual Number of Deaths	226	226	136	136
Actual/Expected Deaths (A)	1.101	0.896	1.452	1.267
Credibility Factor (B) Results reflect a level of accuracy of +/-5% with a 90% confidence level	0.330	0.304	0.320	0.302
Resulting Adjustment Factor 1+[(A) – 1] x (B) To Be Applied to Standard Mortality Rates	103.3%	96.8%	114.5%	108.0%

Mortality: Age-adjusted death rates by state

- The following graph shows age-adjusted death rates for PA, KY, and US from 2002-2008
- Reflects age-adjusted death rates derived from US Census Bureau* (i.e., does not reflect an actuarial mortality study or PPL/LKE-specific data)



* Source: U.S. Census Bureau, Statistical Abstract of the United States: 2012

Mortality: Static vs generational projections

	Static (Current PPL/LKE Assumption)	Generational
Example	A 60 year old today has the same improvement factor as a 60 year old, 5 years from today	A 60 year old today does not have the same improvement factor as a 60 year old, 5 years from today – Generations travel together
Advantages	• Simpler to use, approximate nature could be viewed as consistent with overall degree of uncertainty in the valuation • Should produce gains up to projection year, followed by losses, if projection is periodically updated, should continuously produce gains	• Seen as better match to the actual population than static, especially when looking at subsets of liabilities (for groups of differing ages, for example) • More transparent – avoids the annual gains created by the static approach of advancing future reductions into current rates (offset by future losses)

Mortality assumption survey:
Year-end 2013 assumption

	August Results		October Results		
Prior Valuation's Base Table and Projection Scale	**All Respondents (n = 157)**	**Utility (n=14)**	**All Respondents (n = 224)**	**Utility (n=22)**	
BASE TABLE					
RP2000 with no collar adjustment	85%	86%	79%	86%	PPL/LKE
RP2000 with collar adjustment	11%	7%	15%	9%	
Other	4%	7%	6%	5%	
PROJECTION SCALE					
PPA static projection	47%	57%	44%	41%	PPL/LKE
Scale AA generational	12%	0%	17%	14%	
Scale AA projected more than 10 yrs.	4%	0%	6%	9%	
Scale AA projected 5-10 yrs.	16%	7%	15%	9%	
Scale AA projected less than 5 yrs.	13%	7%	11%	9%	
Some form of BB	6%	29%	6%	18%	
Other projection	1%	0%	1%	0%	
No projection	1%	0%	1%	0%	

Like PPL the majority of other plan sponsors used RP2000 base tables with the PPA static projection scale for their most recent measurement (e.g. 12/31/2013)

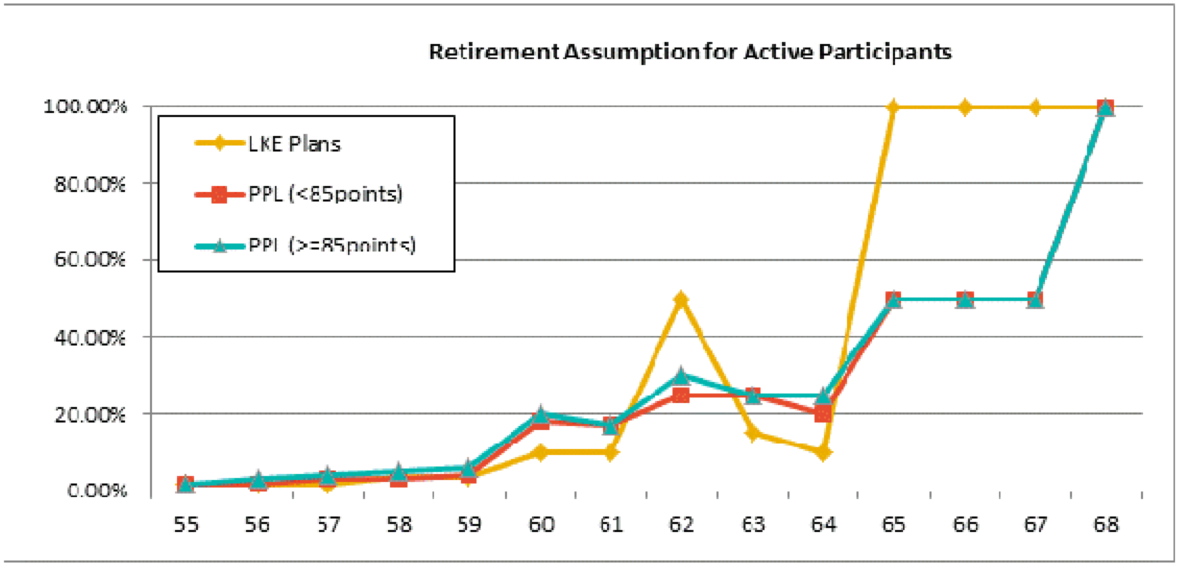
Mortality assumption survey:
Adoption of new SOA tables

Plans for Adoption of New Mortality Basis (Basis and Timing)	*August Results* All Respondents (n = 157)	*August Results* Utility (n=14)	*October Results* All Respondents (n = 224)	*October Results* Utility (n=22)
NEW MORTALITY BASIS				
Not considered / not changing	47%	36%	29%	32%
Reflecting full RP2014/MP2014	26%	43% PPL/LKE	37%	45% PPL/LKE
Reflecting a variation of RP2014/MP2014	14%	14%	20%	5%
Mortality improvement other than RP2014/MP2014 tables	10%	0%	12%	9%
Other	3%	7%	2%	9%
TIMING				
N/A – Not considered/not changing	47%	36%	29%	32%
Plan to adopt at fiscal year-end 2014	19%	14%	38%	32%
Reconsider at fiscal year-end 2015	27%	36%	21%	22%
Reconsider at fiscal year-end 2016	1%	7%	1%	5%
Did not reply	6%	7%	11%	9%

Retirement, Termination, Compensation Increases and Secondary Demographic Assumptions

Retirement assumption: Current assumptions

- Rate represents the number of people expected to retire in a year as a percentage of the number of employees eligible for retirement at that age
- Current retirement assumption yields an average retirement age of 62 for PPL and LKE
- Retirement rates are typically correlated to the richness of the benefits offered



- Trends may impact future behavior:
  - Social Security Normal Retirement Age is increasing from age 65 to 67
  - As the economy improves, increased turnover and earlier retirement are expected
  - Plan changes (Pension and/or Retiree Medical)
  - Longevity perception

Retirement assumption: PPL plans analysis

- Observations:
  - With exception of certain ages, actual experience is similar to assumed experience
  - Employees continue to work beyond age 65
  - PPL Subsidiary Plan has lower than expected retirements at certain ages
- Considerations:
  - Update retirement assumption at certain ages to reflect experience
  - Continue to use consistent assumption for PPL Retirement Plan and PPL Subsidiary Plan

	Current Assumption*	PPL Retirement Plan Experience			Assumption for Consideration
		2003-2008	2009-2011	2012-2014	
55	2%	3%	4%	3%	3%
56	3%	4%	5%	3%	3%
57	4%	4%	5%	6%	4%
58	5%	5%	5%	5%	5%
59	6%	7%	11%	9%	10%
60	20%	21%	20%	26%	20%
61	17%	17%	21%	20%	20%
62	30%	26%	34%	41%	40%
63	25%	28%	23%	30%	25%
64	25%	21%	30%	27%	25%
65	50%	33%	51%	48%	50%
66	50%	33% (reflects cumulative experience after age 65; exposure of 66 participants)	40%	31%	50%
67	50%		30%	45%	50%
68+	100%		17%	26%	100%

* Current assumption shown for participants with 85 points or greater. Assumption reflects adjustments made as a result of the 2011 experience study.

Retirement assumption: LKE plans analysis

- It is our understanding that early retirement experience in the LKE plans was "light" for approximately 10 years due to organized reductions in the workforce in 2001
- Observations:
  - Approximately 4% of employees retire pre-55
  - Workforce reductions appeared to impact actual experience shown, however, future experience is expected to be more heavily dictated by plan provisions
  - Employees continue to work beyond age 65 (and beyond age 66 in the non-union plan)
- Considerations:
  - Extend the table beyond age 65
  - Update retirement table to reflect experience
  - Modify table based on early retirement provision changes

	Current Assumption	Nonunion and Union Experience (2011-2014)	Proposed Assumption	
			Non-union Plan	Union Plan
55	2%	2%	3%	
56	2%	2%	3%	
57	2%	2%	4%	
58	4%	3%	5%	
59	4%	4%	5%	
60	10%	4%	5%	
61	10%	7%	10%	
62	50%	16%	40%	
63	15%	20%	20%	
64	10%	14%	15%	
65	100%	15%	15%	
66	100%	19%	50%	100%
67	100%	21%	50%	100%
68	100%	11%	50%	100%
69+	100%	75%	100%	

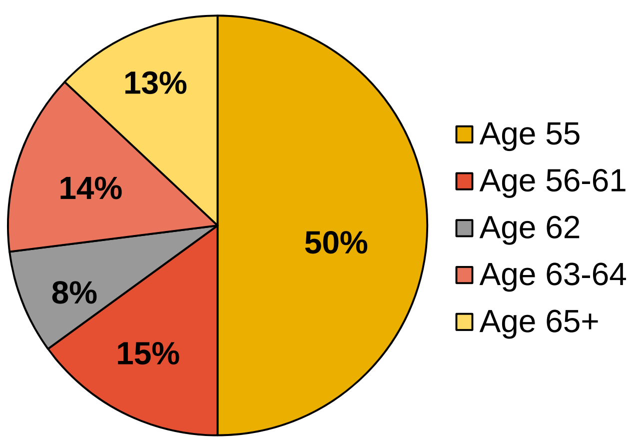
Retirement for terminated vested (TV) participants: PPL

- PPL's valuations reflect single retirement age assumption (age 60) TV's
- Most recent experience indicates that the average retirement age for TV's in the PPL Retirement Plan is remaining consistently around age 60
- In the PPL Subsidiary Retirement Plan, 10 TV's retired during the most recent three years with an average retirement age of 58
- Consideration: Retain age 60 assumption

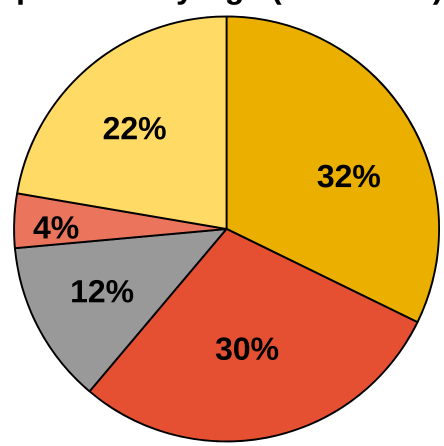
PPL Retirement Plan: Average TV Retirement Age by Year

2003-2004	57.8	2009-2010	58.5
2004-2005	57.1	2010-2011	60.8
2005-2006	57.0	2011-2012	60.7
2006-2007	58.1	2012-2013	60.7
2007-2008	59.6	2013-2014	58.7

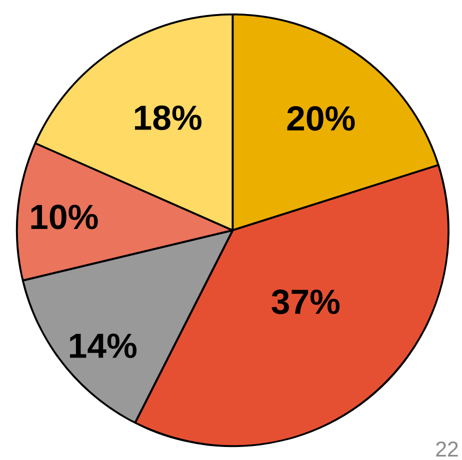
PPL Retirement Plan: TV Retirement Experience by Age (2003-2008)



PPL Retirement Plan: TV Retirement Experience by Age (2009-2011)



PPL Retirement Plan: TV Retirement Experience by Age (2012-2014)



Retirement for terminated vested participants - LKE

- LKE plan valuations reflect a single retirement age assumption for Terminated Vested (TV) participants

	LG&E (Pre-Plan Change)*	LG&E (Post-Plan Change)*	KU
Current Assumption	65	55	55 if 10 YOS 65 if <10 YOS

- Considerations
  - For LG&E participants who terminated prior to the change in the ERF, assume age 60
  - For LG&E participants who terminated on or after the improvement in the ERF and KU participants with at least 10 years of service, assume age 58

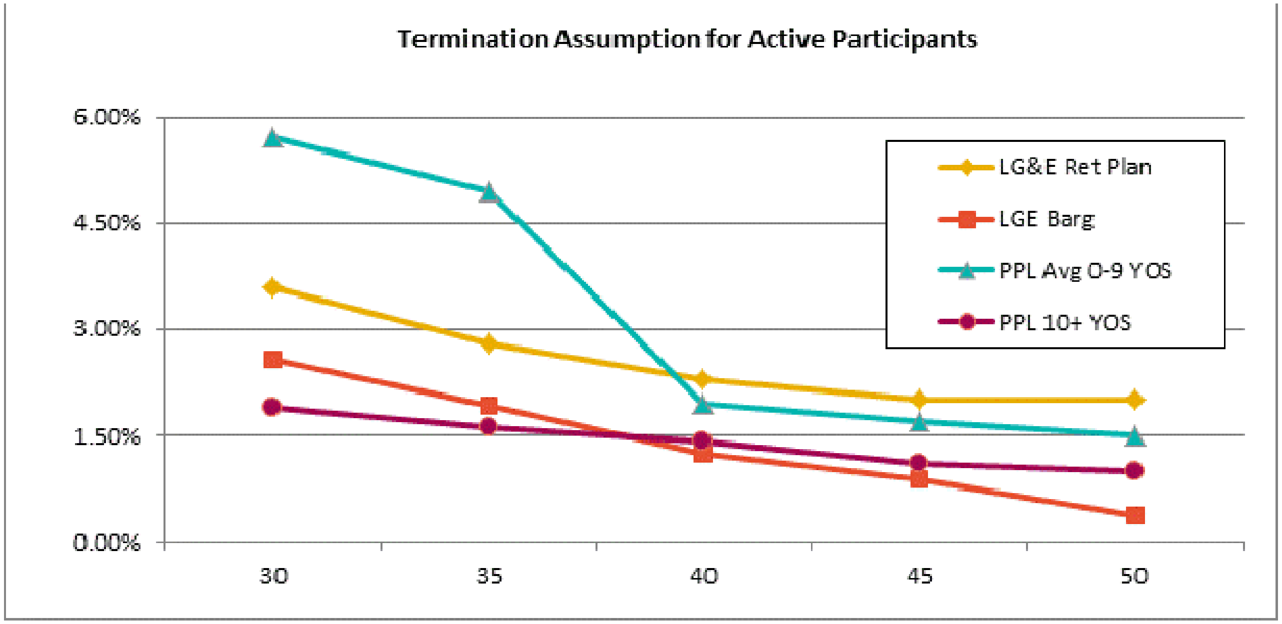
Average TV Retirement Age by Year

	LG&E (Pre-Plan Change)	LG&E (Post-Plan Change)	KU
2011-2012	61.0	59.1	
2012-2013	59.6	57.4	
2013-2014	59.9	58.1	
Cumulative	60.0	58.3	
Proposed Assumption	60	58	58 if 10 YOS 65 if <10 YOS

*Plan change improving early retirement factors was 1/1/2004 for union and 10/1/2003 for non-union.

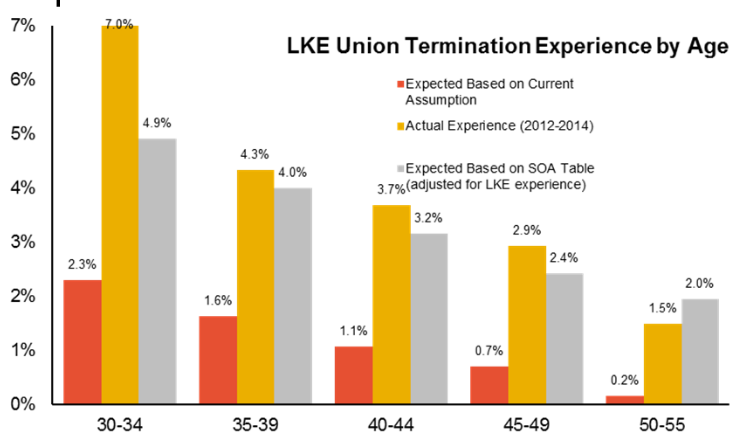
Termination assumption: Current assumptions

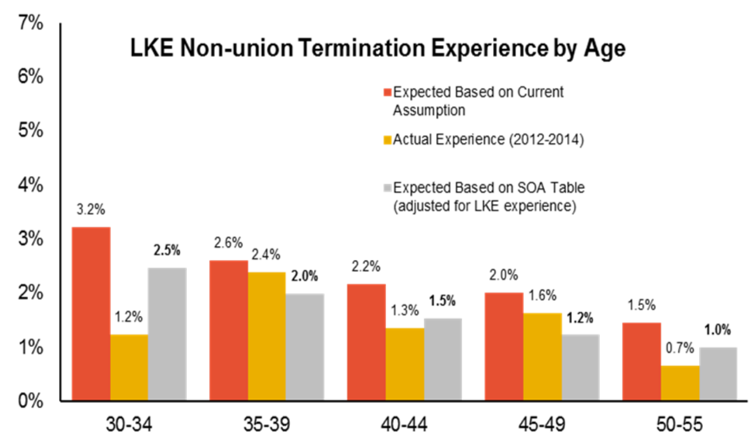
- Termination patterns can be influenced by age, service, industry, economic environment
- PPL uses an age & service based termination assumption (i.e., select and ultimate table)
- LKE uses an age based termination assumption
  - Since the plans were closed in 2006, all participants will be older than 25; most participants will be over 30
- The termination assumptions for all plans converge at approximately age 40



Termination assumption: LKE plans

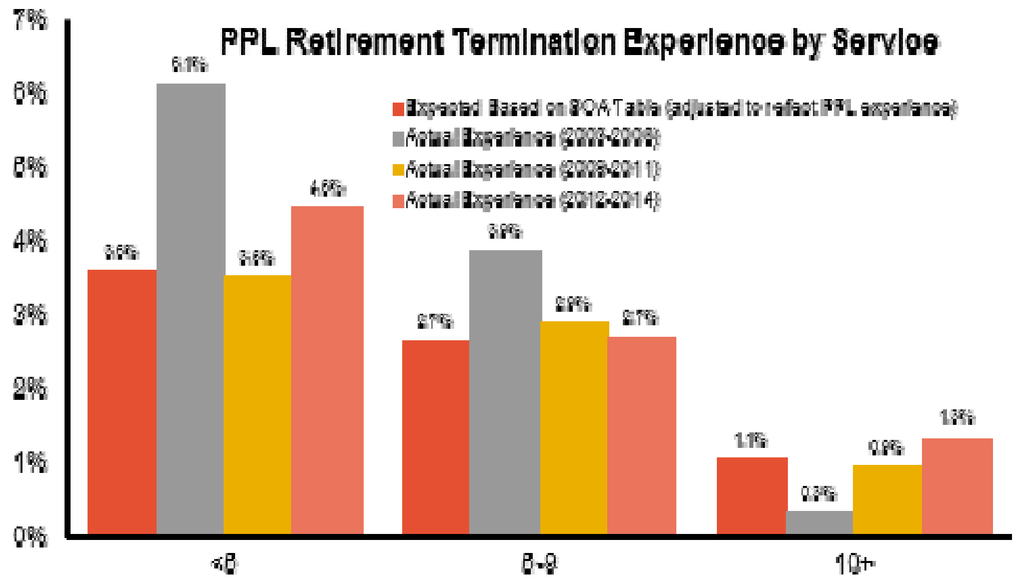
- LKE uses separate termination tables for union and non-union plans based on age only
  - Since the plans were closed in 2006, very few participants with less than 10 years of service remain, so no need for a select period based on service
- Observations:
  - Union: Overall cumulative termination experience is <u>higher</u> than cumulative assumed termination experience (7 expected, 23 actual)
  - Non-union: Overall cumulative termination experience is <u>lower</u> than cumulative assumed termination experience (57 expected, 38 actual)
  - Current experience follows the SOA Hourly Union Termination Table (with adjustment for union plan)
- Consideration:
  - Adopt the SOA Hourly Union Termination Table for the union (with modifications) and non-union plans and continue to monitor turnover experience





Termination assumption: PPL plans

- PPL uses a termination table based on age and service
  - SOA union hourly select and ultimate table with increased termination adjustments at ages 30-39 for participants with less than 10 years of service (see appendix for additional details)



- Observations:
  - Overall termination experience (2012-2014) is similar to assumed termination experience especially for participants with greater than 5 years of service
    - 263 actual terminations vs. 225 expected terminations (overall exposure base over 10,000)
  - For the PPL Subsidiary Retirement Plan, actual experience is higher than expected, however, small number of plan participants during exposure periods yields less credible results (on its own)
- Consideration:
  - Retain current table and continue to monitor turnover experience

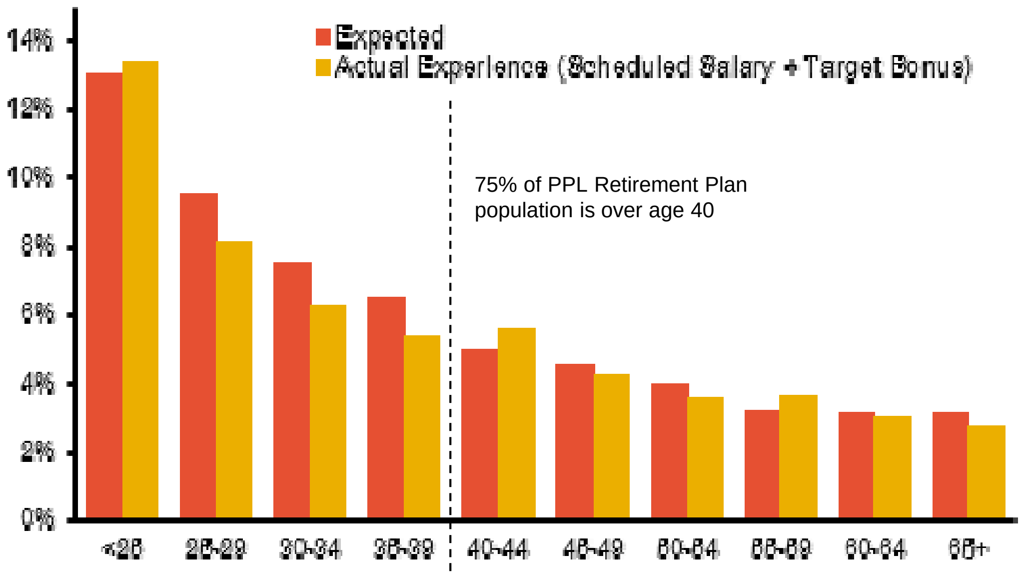
Compensation increase assumption

- Recent experience and anticipated future changes to compensation levels should be considered when developing assumptions
  - Does PPL or LKE anticipate any fundamental shifts in management or union policies in the future?
- Assumption should consider the definition of pensionable pay for each plan
- SERP plans tend to have more volatile gains/losses due to compensation increases because of small number of plan participants and uncapped pay
  - Select and ultimate table could bridge the gap between shorter term budgets and longer term expectations

Age	Year-end 2013 Assumption		
	PPL Qualified Plans	PPL SERP	LKE Plans
<25	13.00%	5.25%	4.00%
25-29	9.50%		
30-34	7.50%		
35-39	6.50%		
40-44	5.00%		
45-49	4.50%		
50-54	4.00%		
55-59	3.20%		
60+	3.10%		

Compensation increase assumption: PPL Retirement Plan

- Observations:
  - Experience is lower than assumed for participants between the ages of 25 and 39
  - Experience is generally consistent with the assumption for ages less than 25 and greater than 40
  - For the PPL Subsidiary Retirement Plan, actual experience for participants less than age 50 is less than expected, most notably for participants less than age 30.
- Consideration:
  - Decrease assumption by 0.5% for ages 25-39

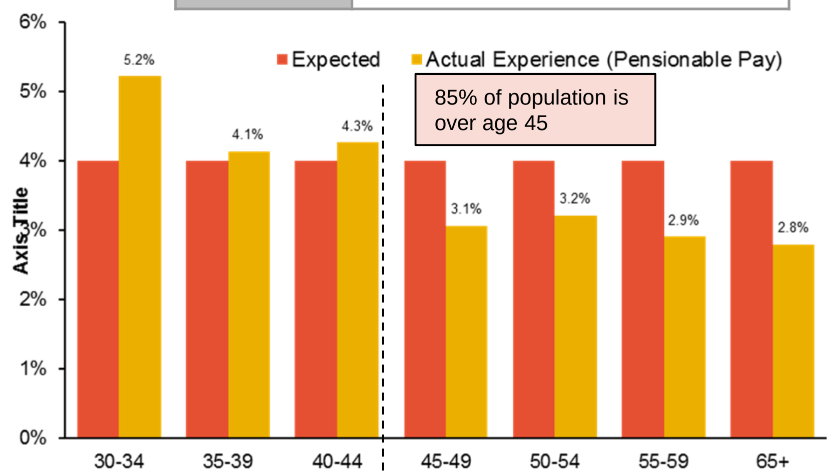


Age	Current	Consideration
<25	13.0%	13.0%
25-29	9.5%	9.0%
30-34	7.5%	7.0%
35-39	6.5%	6.0%
40-44	5.0%	5.0%
45-49	4.5%	4.5%
50-54	4.0%	4.0%
55-59	3.2%	3.2%
60+	3.1%	3.1%
"Valuation Equivalent" Flat Rate (2013)	3.94%	n/a
"Valuation Equivalent" Flat Rate (2012)	3.95%	n/a

Compensation increase assumption: LKE Plans

- Results represent the average actual pay increases for the non-union plan for participants who were active on both current and prior valuation dates (excludes pay in excess of the maximum annual salary limit)
- Consideration:
  - Qualified Plan: Decrease assumption by 0.5% to reflect aging closed population
  - SERP (data not shown):
    - Consider increase in assumption for this executive population
    - Consider changing the basis for pay projection in the SERP to mitigate volatility

Year	LKE Nonunion Retirement Plan Pay Experience*
2004	5.24%
2005	4.01%
2006	5.85%
2007	3.39%
2008	4.99%
2009	4.62%
2010	3.14%
2011	3.34%
2012	2.18%
2013	4.15%

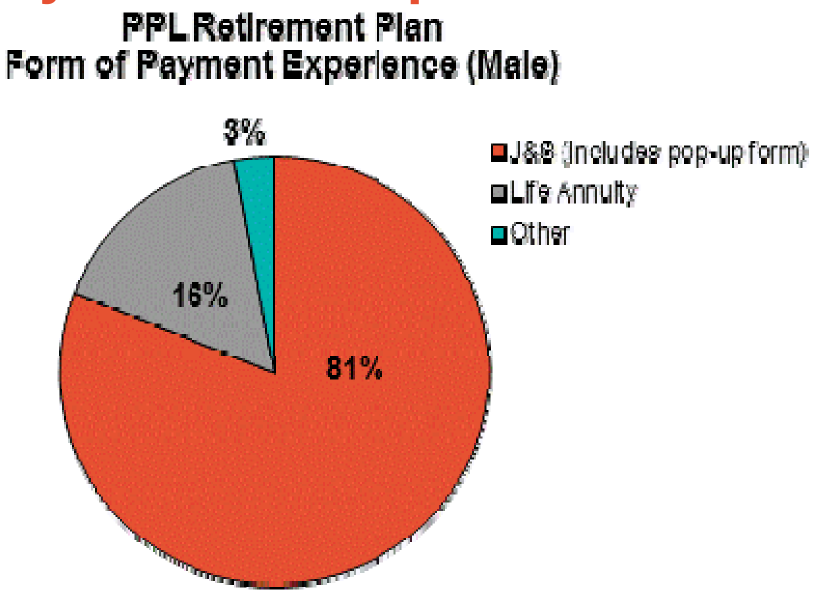


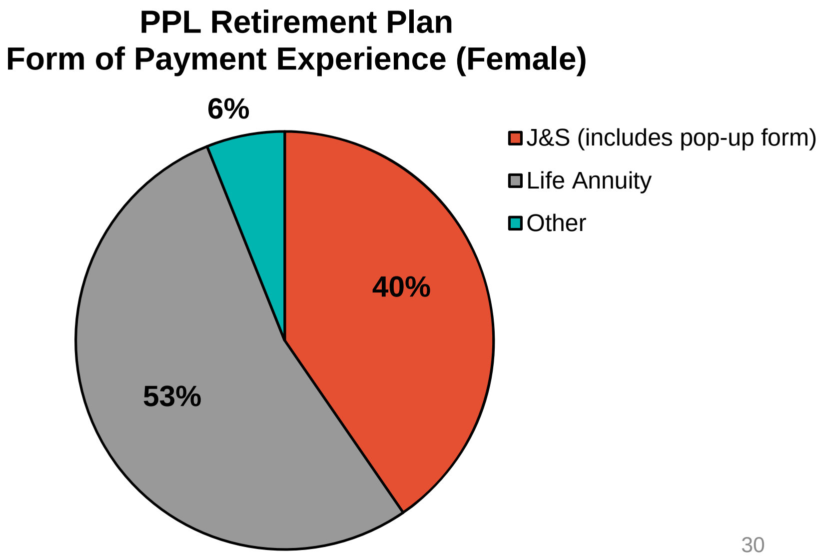
Secondary Assumptions: Form of Payment – PPL plans

PPL Retirement Plan & PPL Subsidiary Plan

Current	• Males: 90% J&S, 10% Life Annuity • Females: 60% J&S, 40% Life Annuity • Males assumed to be 3 years older than females
Proposed	• Non-union Males: 50% Lump Sum, 40% J&S, 10% Life Annuity • Non-union Females: 50% Lump Sum, 20% J&S, 30% Life Annuity • Union Males: 80% J&S, 20% Life Annuity • Union Females: 40% J&S, 60% Life Annuity • Males assumed to be 3 years older than females

- Beginning 1/1/2015, a lump sum will be available for non-union participants in the PPL Retirement Plan
  - Assumed take rate from the TV window was 50%
- Consider mirroring TV window election percentage for future lump sum payments
- Consider reducing J&S election percentage



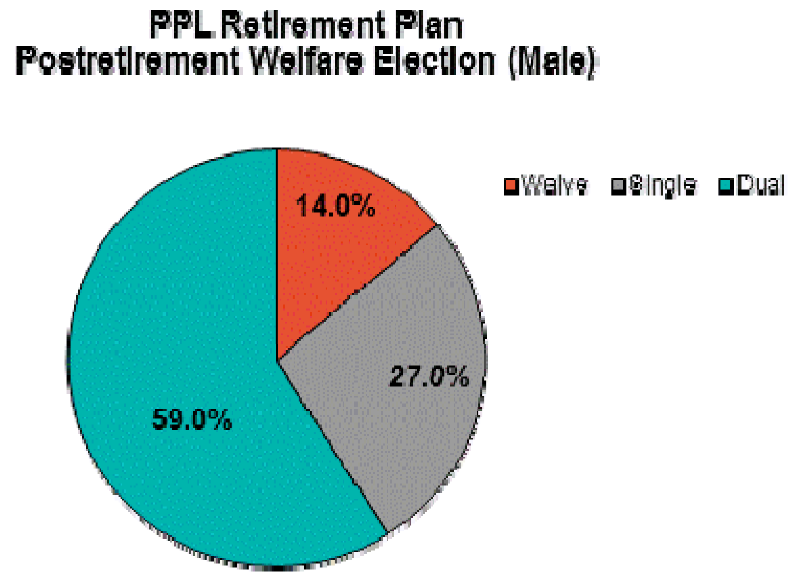


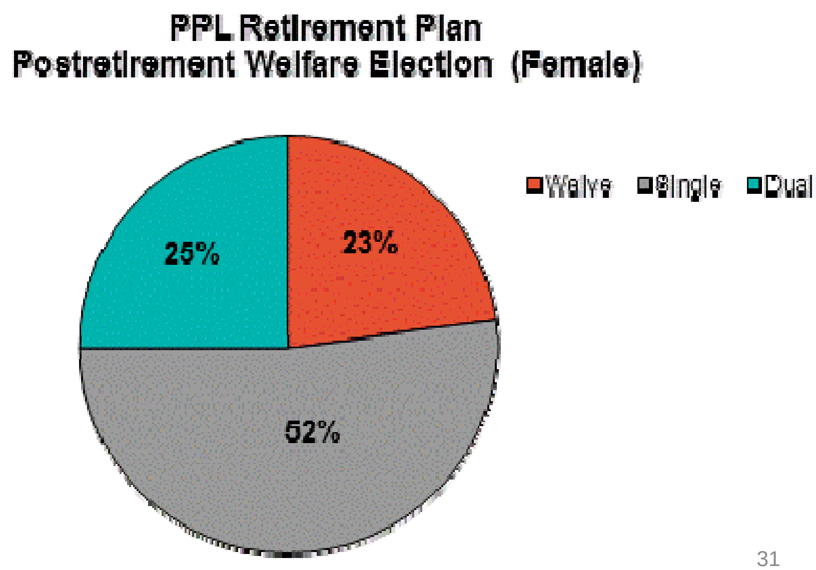
Secondary Assumptions: Postretirement Welfare Participation – PPL plans

Medical benefits in the PPL Postretirement Welfare Plan and Montana Postretirement Welfare Plan

Current	• Males: 81% dual, 19% single • Females: 36% dual, 64% single
Proposed	• Males: 60% dual, 30% single, 10% waive • Females: 30% dual, 60% single, 10% waive

- Experience reflects the most recent elections made by retiring participants
- Observations:
  - A portion of participants are electing to waive PPL medical coverage
  - For participant who elect coverage, less than expected are electing dual coverage
- Consideration:
  - Consider introducing a waive assumption
  - Consider reducing the percent electing dual coverage





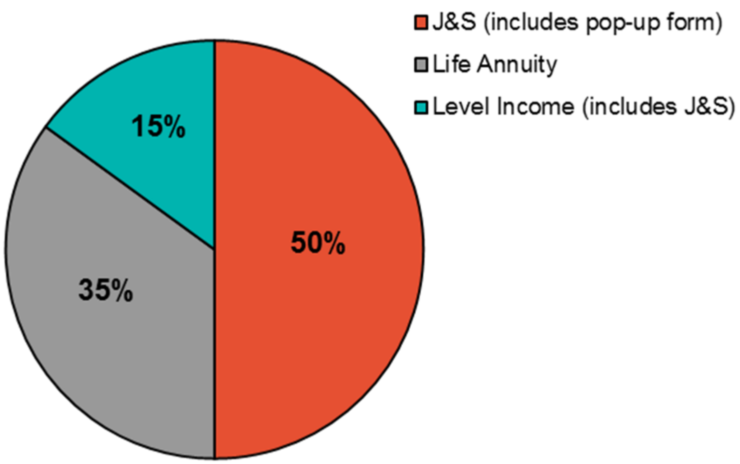
Secondary Assumptions: Form of Payment – LKE plans

LKE Qualified Plans

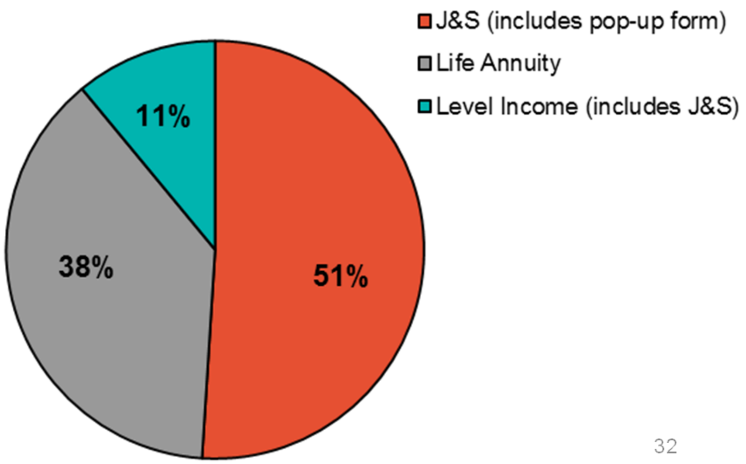
Current	LG&E: 100% Life Annuity KU: 25% Life Annuity, 75% "free" J&S Males assumed to be 3 years older than females
Proposed	LG&E: 25% Life Annuity, 75% J&S KU: 25% Life Annuity, 75% "free" J&S Males assumed to be 3 years older than females

- Observations:
  - The union and non-union plans have similar experience with approximately 50% of new retirees electing a J&S option (experience excludes election of KU "free" 50% J&S benefit)
  - Many of the level income form of payment elections include a J&S component as well
- Consideration:
  - For KU participants, no changes to the current assumption
  - For LG&E participants, consider changing form of payment assumption to reflect life annuity if single; 50% Joint and Survivor (J&S) if married

Non-union Plan
Form of Payment Experience



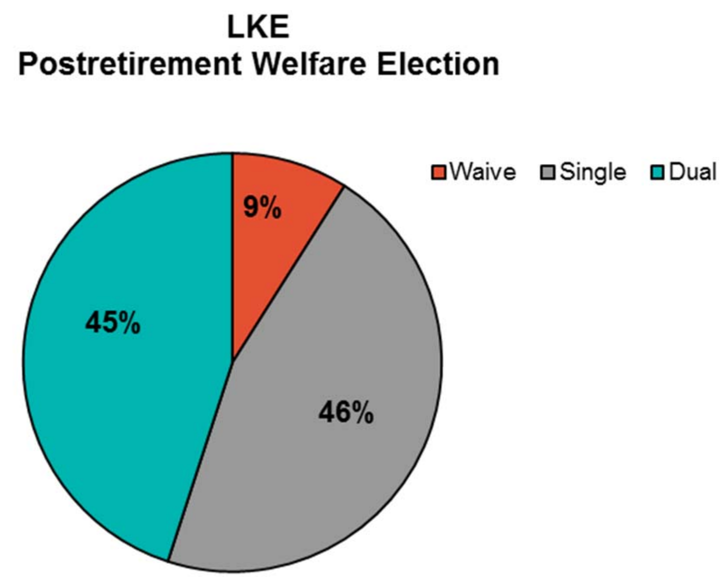
Union Plan
Form of Payment Experience



Secondary Assumptions: Postretirement Welfare Participation – LKE plan

LKE Postretirement Welfare Plan

Participation for Future Retirees	100% of eligible participants for both medical and life insurance;
Dual coverage	75% for all; males 3 years older than females



- Observations:
  - Experience reflects participants eligible for the medical credit (the plan does not currently have actual experience under the retiree medical account)
  - There is not enough experience to determine dependent participation assumptions split by gender
  - Approximately half of plan participants elect coverage for dependent spouses
- Consideration:
  - Understand reason for single elections and consider reducing assumption
  - Maintain current participation assumption due to plan design

Secondary Assumptions: Disability - LKE plans

- Disability rates are used to estimate when participants will disable
  - Generally used for valuation of plans that provide disability benefits
  - If disability rates are used, then often a disability-mortality assumption is also used
  - Disability-mortality rates are based upon the assumption that a person is already disabled
- LKE participants have shown low disability incidence over the past two years (typically at a rate between 0.4% and 0.6% per year)
- Experience is generally consistent with the assumption for the non-union plan but lower than expected for the union plan
- Consider retaining the non-union plan assumption and using for both plans

	Non-union		Union	
	2012	2013	2012	2013
Total actives	1,896	1,831	530	515
New disablements	9	9	3	2
Actual %	0.47%	0.49%	0.57%	0.39%
Expected %	0.69%	0.71%	1.38%	1.55%

Plan	Disability Benefit Description	Determination of Disability Benefit in Valuation
Non-union Plan	No explicit disability benefit; however, plan offers additional service while on LTD and the FAE is based upon pay as of disability date	Age based male and female disability assumption
Union Plan	No explicit disability benefit; however, plan offers additional service to normal retirement date while on LTD	Age based disability assumption

Secondary Assumptions: Disability – PPL plans

- Historically, PPL Retirement Plan participants have shown low disability incidence (typically between the ages of 50 and 55 at a rate between 0.2% and 0.7% per year)
- Consider retaining current valuation methodology (negligible impact on valuation obligations)

	2014	2013	2012	2011
New Disabled Participants	37	17	39	14
Total Disabled Participants	136	119	125	111
Total Active Participants (Prior Year)	5,689	5,946	5,911	5,843
% New Disabled / Total Active	0.65%	0.29%	0.66%	0.24%

Plan	Disability Benefit Description	Determination of Disability Benefit in Valuation
PPL Retirement Plan	No explicit disability benefit; however, plan offers additional service while on LTD and the FAE is based upon pay as of disability date	No explicit disability benefit is determined in the valuation (load of 0.3% applied to active ERISA obligations to reflect anticipated disability experience)
PPL Subsidiary Retirement Plan	Cash balance account continues to grow with contributions and interest credits based on earnings prior to becoming disabled	Explicit disability assumption

Demographic assumption summary

Key Demographic Assumptions	Year-end 2013 Assumptions	Method for Review	Year-end 2014 Assumptions/Methods **[PRELIMINARY]**
Mortality	**PPL**: IRS prescribed for minimum funding **LKE**: IRS prescribed for minimum funding	Review of recent mortality studies, consistency throughout organization	
Retirement	Active – Age based tables Term vested – age 60 (PPL Ret Plan), 60 (Subs Plan); 55 or 65 depending on year of termination (LKE Plans)	Year-end 2014 experience study	
Termination	**PPL**: Age and Service based table **LKE**: Age based table		
Compensation Increase Rate	**PPL**: Age graded table for qualified plans, 5.25% for SERP plan **LKE**: 4.00% for all plans		
Disability	Varies by plan		
Form of Payment	**PPL**: Males 90% J&S, females: 60% remainder single **LKE**: LG&E: 100% Life Annuity, KU: 25% Life Annuity, 75% free 50% J&S		
PRW participation	**PPL**: Males 81% dual, females 36% dual, remainder single **LKE**: 75% dual, 25% single		

Next Steps

Next Steps

- Confirm alternate sets of assumptions for financial analysis (Phase II)
- Estimated ASC 715 expense, balance sheet, and ERISA funding impact (approximately 3-4 weeks after confirmation)
- Discuss economic assumptions
- Determine final demographic and economic assumptions
- Reflect updates in the December 31, 2014 disclosure results
- Determine if IRS approval needed to implement in the funding valuation (excluding mortality and compensation increase)

Appendix

Actuarial Certification

The results included in this presentation were prepared under our direction. They are based upon census data, asset data and plan provisions provided by PPL Corporation. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. The accuracy of the results in this presentation is dependent upon the accuracy and completeness of the underlying information.

Actuarial assumptions and methods as of December 31, 2013 were selected by PPL Corporation with the concurrence of Towers Watson. More detailed valuation results, summaries of actuarial methods and assumptions, summaries of plan provisions and description of data sources used in developing these results can be found in the 2014 valuation reports.

The consulting actuaries are members of the Society of Actuaries and other professional actuarial organizations and meet their “General Qualification Standard for Prescribed Statements of Actuarial Opinion” relating to pension and postretirement welfare plans.

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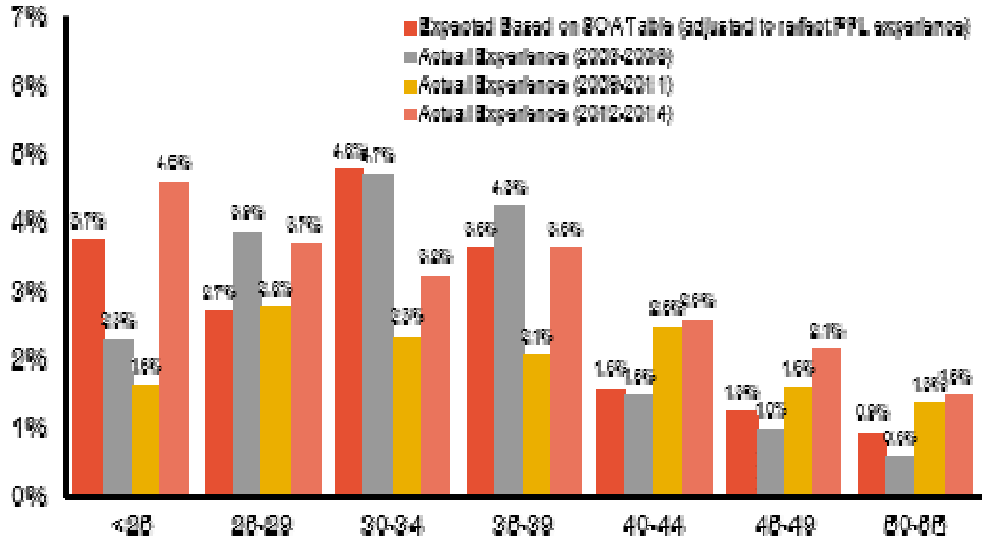
Note: This presentation was developed for the internal use of PPL Corporation in connection with its year-end 2014 assumption setting process. It is not intended nor necessarily suitable for other purposes. Further distribution or use of all or part of this material is prohibited without prior written consent.

Appendix: Termination Rates (additional details)

Age	Service 1	Service 2	Service 3	Service 4	Service 5-9	Service 10+
18	5.4%	0.0%	0.0%	0.0%	0.0%	0.0%
19	5.2%	4.8%	4.8%	4.8%	0.0%	0.0%
20	5.1%	4.6%	4.6%	4.6%	0.0%	0.0%
21	4.9%	4.4%	4.4%	4.4%	2.2%	0.0%
22	4.8%	4.2%	4.2%	4.2%	2.2%	0.0%
23	4.6%	4.0%	4.0%	4.0%	2.2%	0.0%
24	4.5%	3.8%	3.8%	3.8%	2.2%	0.0%
25	4.3%	3.6%	3.6%	3.6%	2.2%	0.0%
26	4.2%	3.4%	3.4%	3.4%	2.1%	2.2%
27	4.1%	3.2%	3.2%	3.2%	2.1%	2.2%
28	4.0%	3.1%	3.1%	3.1%	2.1%	2.1%
29	3.8%	2.9%	2.9%	2.9%	2.1%	2.0%
30	**7.4%**	**8.4%**	**8.4%**	**5.6%**	**4.0%**	1.9%
31	**7.2%**	**7.8%**	**7.8%**	**5.2%**	**4.0%**	1.9%
32	**7.0%**	**7.5%**	**7.5%**	**5.0%**	**4.0%**	1.8%
33	**6.8%**	**7.2%**	**7.2%**	**4.8%**	**4.0%**	1.7%
34	**6.6%**	**6.9%**	**6.9%**	**4.6%**	**4.0%**	1.7%
35	**6.4%**	**6.6%**	**6.6%**	**4.4%**	**3.8%**	1.6%
36	**6.2%**	**6.0%**	**6.0%**	**4.0%**	**3.8%**	1.6%
37	**6.0%**	**5.7%**	**5.7%**	**3.8%**	**3.8%**	1.5%
38	**5.8%**	**5.4%**	**5.4%**	**3.6%**	**3.8%**	1.5%
39	**5.6%**	**5.1%**	**5.1%**	**3.4%**	**3.8%**	1.4%
40	2.7%	1.7%	1.7%	1.7%	1.8%	1.4%
41	2.6%	1.6%	1.6%	1.6%	1.8%	1.3%
42	2.6%	1.5%	1.5%	1.5%	1.8%	1.3%
43	2.5%	1.4%	1.4%	1.4%	1.8%	1.2%
44	2.4%	1.4%	1.4%	1.4%	1.8%	1.2%
45	2.3%	1.3%	1.3%	1.3%	1.7%	1.1%
46	2.3%	1.2%	1.2%	1.2%	1.7%	1.1%
47	2.2%	1.2%	1.2%	1.2%	1.7%	1.1%
48	2.1%	1.1%	1.1%	1.1%	1.7%	1.0%
49	2.0%	1.0%	1.0%	1.0%	1.7%	1.0%
50	2.0%	1.0%	1.0%	1.0%	1.6%	1.0%
51	1.9%	0.9%	0.9%	0.9%	1.6%	0.9%
52	1.9%	0.9%	0.9%	0.9%	1.6%	0.9%
53	1.8%	0.8%	0.8%	0.8%	1.6%	0.8%
54	1.7%	0.8%	0.8%	0.8%	1.6%	0.8%

- The general make-up of the PPL termination rate table is based on the SOA Hourly Union Select Termination Table
  - Rates were adjusted to better reflect PPL experience based on 2008 experience study
  - Rates highlighted in yellow are 2x the rates in the standard SOA table
  - Rates highlighted in purple are 3x the rates in the standard SOA table

PPL Retirement Plan Termination Experience by Age



Appendix: Termination Rates (additional details) LKE plans

Age	Non-union	Union
30	2.7%	5.4%
31	2.6%	5.2%
32	2.5%	5.0%
33	2.4%	4.8%
34	2.3%	4.6%
35	2.2%	4.4%
36	2.1%	4.2%
37	2.0%	4.0%
38	1.9%	3.8%
39	1.8%	3.6%
40	1.7%	3.4%
41	1.6%	3.2%
42	1.6%	3.2%
43	1.5%	3.0%
44	1.4%	2.8%
45	1.4%	2.8%
46	1.3%	2.6%
47	1.2%	2.4%
48	1.2%	2.4%
49	1.1%	2.2%
50	1.1%	2.2%
51	1.0%	2.0%
52	1.0%	2.0%
53	0.9%	1.8%
54	0.9%	1.8%

- The general make-up of the recommended LKE termination rate tables is based on the SOA Hourly Union Termination Table
  - Rates were unadjusted for non-union participants
  - Rates were doubled to better reflect union experience

Appendix: Components of a mortality projection scale

- A mortality projection scale involves selection of
  - Generational approach vs. static approach
  - If generational, one-dimensional vs two-dimensional
    - One dimensional – improvement rates are the same for all years for a given age (that is, improvement factors are the same at a given age, regardless of the year of birth of the person at that age)
    - Two dimensional – improvement rates vary based on age and year of birth
  - If two dimensional, must choose ultimate rates, beginning rates, convergence period and mathematical model to converge beginning rates to ultimate rates

Appendix: Examples of projection scales

- Static – rates are all reduced by a percentage (which can vary by age) for a specified number of years, and these rates are used for all years in the valuation
  - Example – scale AA, age 60, statically applied for seven years after the valuation date
  - Valuation in 2015; static projection is to 2022
  - Mortality rate is reduced by $(1-.016)^{22}$,or .701
  - The resulting rate applies in 2015, 2016….2022, 2023….forever
- Generational, one dimensional – mortality rates improve* every year in the future, with improvement rates generally varying by age
  - Example – scale AA, age 60
    - Annual improvement is 1.6%
    - The year 2000 rate is adjusted by this improvement factor for the number of years that have elapsed since 2000
    - So, rate in 2015 is the 2000 rate multiplied by $(1-.016)^{15}$,or .785
    - Rate in 2016 is 2000 rate multiplied by $(1-.016)^{16}$,or .773
    - Rate in 2022 is 2000 rate multiplied by $(1-.016)^{22}$,or .701
    - Rate in 2023 is 2000 rate multiplied by $(1-.016)^{23}$,or .690

*Note that improvement rates can be negative at certain ages/years

Appendix: Examples of projection scales

- Generational, two dimensional – mortality rates generally improve every year in the future*, with improvement rates generally varying by age and year of birth
  - Example – scale MP-2014, female age 60 in 2007 (born in 1947) and female age 60 in 2012 (born in 1952)

Age	Improvement Factor: 2007+	
	Age 60 in 2007	Age 60 in 2012
55	N/A	.72%
56	N/A	.87%
57	N/A	1.02%
58	N/A	1.18%
59	N/A	1.34%
60	2.10%	1.47%
61	2.21%	1.57%
62	2.29%	1.63%
63	2.34%	1.64%
64	2.35%	1.62%

*Note that improvement rates can be negative at certain ages/years

Appendix: The MP-2014 scale – Use of near-term improvement rates

- The model reflected historical improvement rates through 2007
- Near-term projected rates (e.g., 2008-2014) are highly dependent under this method of recent rates and the slope of change in those rates
- Ending period coincided with a period of historically high improvement rates and, at many ages, a positive slope of improvement rates

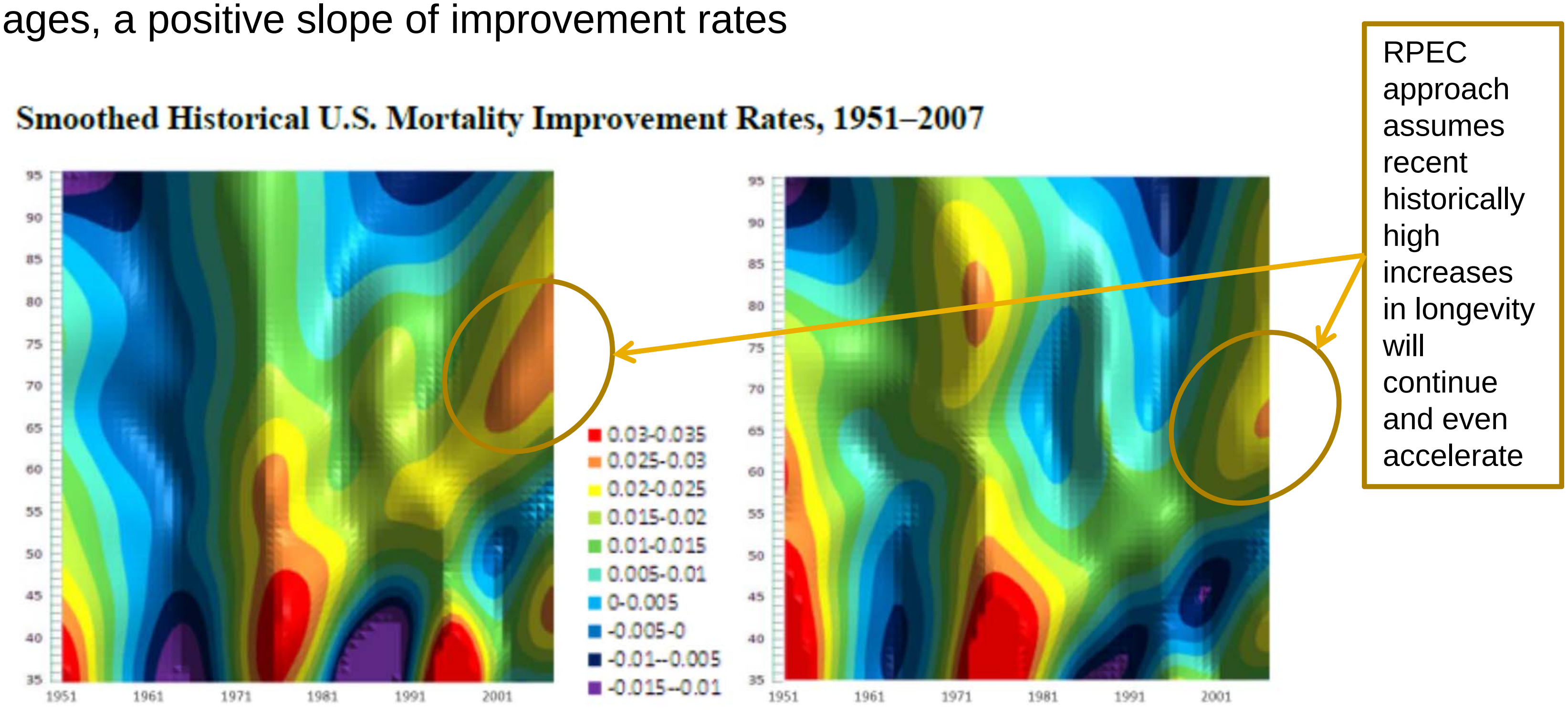
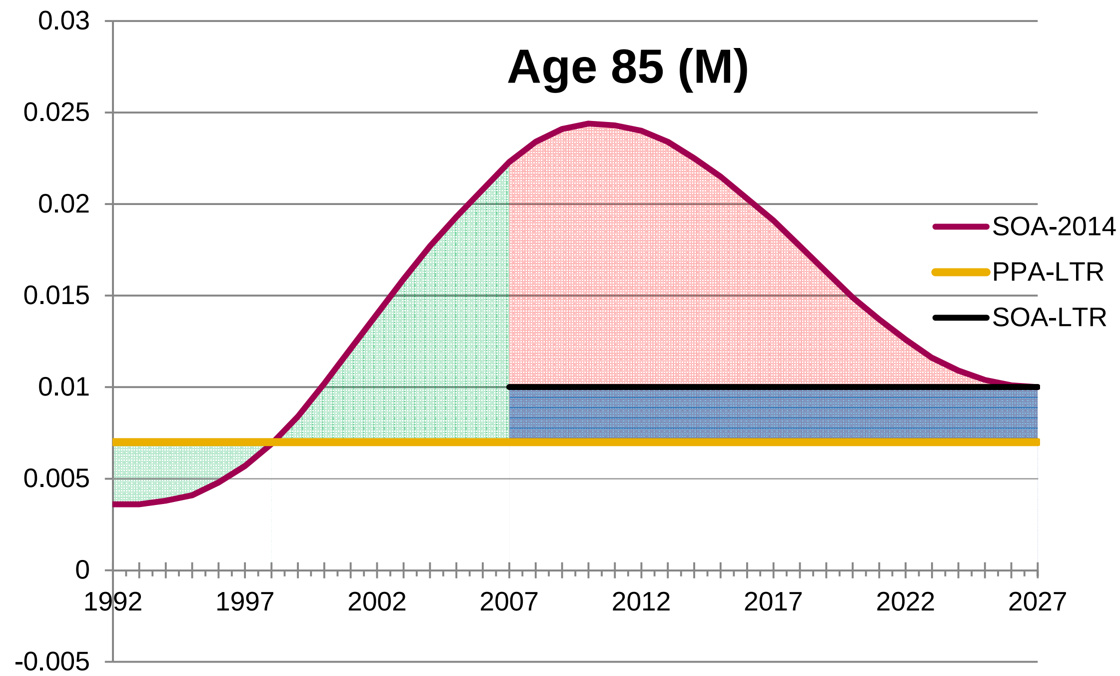


Figure 1(M)

Figure 1(F)

Appendix: Graphic view of mortality improvement –
3 Steps to understanding / adopting the new tables

- RPEC tables
  - Based near-term improvement rates on historical observations
  - Used a 1% long-term improvement rate
  - Assumed rates would trend from near-term to long-term rates over 20 years
  - Used “a family of cubic polynomials” to connect recent experience and the long-term assumption



Notes

- Green areas marked with “1” represent experience since the last RPEC mortality study
- Blue area marked with “2” represents a change in the RPEC’s long-term mortality improvement expectation
- Red area marked with “3” represents the RPEC’s new approach to projecting mortality in the short-term
- Each area should be evaluated to determine the “best-estimate” assumption for an individual sponsor or plan.

TOWERS WATSON

Mortality Credibility Analysis – Updated12/4/2014
LKE Experience

- Results below reflect LKE non-union plan and LKE union plan mortality experience under the RP-2014 white collar and blue collar tables, respectively
- The RP-2014 tables are based on years of data with a mid-point of 2006 (the base year) and projected to 2014 with the MP-2014 mortality improvement projection scale
- LKE is considering adjusting the standard RP-2014 tables to reflect plan experience
- If tables are adjusted, the factor to be applied to the standard mortality rates, after reflecting the credibility factor, should be based on a comparison of
  - Actual plan experience to
  - RP-2014 projected from the base year using the mortality projection scale selected by LKE for mortality improvements beyond 2014 (for consistency)

LKE (3 years of data)	Non-union RP-2014, White Collar		Union RP-2014, Blue Collar	
Mortality Projection Scale	MP-2014	BB-2D	MP-2014	BB-2D
Total Records (Life-Years)	6,857	6,857	4,675	4,675
Actual Number of Deaths	226	226	136	136
Actual/Expected Deaths (A)	1.101	1.067	1.267	1.235
Credibility Factor (B) Results reflect a level of accuracy of +/-5% with a 90% confidence level	0.330	0.324	0.302	0.298
Resulting LKE Adjustment Factor [(A) – 1] x (B) To Be Applied to Standard Mortality Rates	**+3%**	**+2%**	**+8%**	**+7%**

PENSION	2015 LGE	2015 KU	2015 Servco	2015 Total	2016 LGE	2016 KU	2016 Servco	2016 Total
Revised 2/6/15	$ 17,162,433	$ 15,246,360	$ 22,849,484	$ 55,258,277	$ 9,958,675	$ 10,660,286	$ 20,322,181	$ 40,941,142
O&M %	77%	69%	81%		77%	68%	82%	
O&M Portion of Pension Expense	$ 13,157,495	$ 10,540,055	$ 18,613,186	$ 42,310,735	$ 7,691,943	$ 7,301,862	$ 16,569,102	$ 31,562,907
ServCo Allocation %	45%	54%			45%	54%		
ServCo Allocation	$ 8,343,757	$ 10,141,244	$ (18,485,001)	$ -	$ 7,427,453	$ 9,027,542	$ (16,454,995)	$ -
Total O&M Portion of Pension Expense	$ 21,501,251.77	$ 20,681,299.11	$ 128,184.50	$ 42,310,735.38	$ 15,119,395.68	$ 16,329,404.04	$ 114,107.39	$ 31,562,907.10

Test Year for KU:	
6 months 2015	$ 10,340,649.56
6 months 2016	$ 8,164,702.02
Total	$ 18,505,351.58

Test Year for LG&E:	
6 months 2015	$ 10,750,625.89
6 months 2016	$ 7,559,697.84
Total	$ 18,310,323.72

Utilty Cost of Debt Comparison		
12 Months Ending December 2014		
Rank	Company	Per Public Data
1.	**LG&E**	**3.278%**
2.	**KU**	**3.371%**
3.	Duke Energy Ohio	3.832%
4.	Dayton Power and Light	3.865%
5.	AEP Texas North Company	4.149%
6.	Public Service Electric and Gas Company	4.365%
7.	AEP Texas Central Company	4.390%
8.	Indiana Michigan Power Company	4.442%
9.	Duke Energy Indiana Inc.	4.466%
10.	PECO Energy Company	4.698%
11.	DTE Electric Company	4.716%
12.	NiSource	4.721%
13.	Kentucky Power Company	4.728%
14.	DTE Gas Company	4.788%
15.	PPL Electric Utilities	4.942%
16.	Ohio Power Company	5.099%
17.	Commonwealth Edison	5.122%
18.	Appalachian Power Company	5.127%
19.	Union Electric Company	5.303%
20.	Ameren Illinois Company	5.333%
21.	Metropolitan Edison Company	5.742%
22.	Jersey Central Power & Light Co.	5.827%
23.	Pennsylvania Electric Company	5.966%
24.	Toledo Edison Company	7.733%
25.	Ohio Edison Company	8.661%

http://www.federalreserve.gov/releases/cp/rates.htm

Commercial Paper Rates Derived from data supplied by The Depository Trust & Clearing Corporation

Data as of March 31, 2015Posted April 1, 2015

Daily rates for commercial paper are provided for the AA nonfinancial, A2/P2 nonfinancial, AA financial, and AA asset-backed categories. The criteria that determine which issues are included in the rate categories are detailed in the Rate Calculations section of the About page of this release.

Period	AA nonfinancial						A2/P2 nonfinancial					
	1-day	7-day	15-day	30-day	60-day	90-day	1-day	7-day	15-day	30-day	60-day	90-day
Annual average												
2013	0.06	0.07	0.07	0.08	0.09	0.11	0.25	0.27	0.27	0.30	0.32	0.33
2014	0.06	0.06	0.06	0.07	0.08	0.10	0.21	0.24	0.25	0.27	0.29	0.32
2015*	0.07	0.07	0.07	0.08	0.09	0.12	0.36	0.40	0.44	0.46	0.49	0.52
Monthly average												
2014-Oct.	0.05	0.06	0.06	0.06	0.08	0.10	0.23	0.25	0.26	0.27	0.31	0.34
Nov.	0.06	0.07	0.06	0.07	0.08	0.10	0.25	0.27	0.29	0.30	0.35	0.39
Dec.	0.10	0.10	0.10	0.11	0.11	0.13	0.33	0.39	0.41	0.46	0.47	0.48
2015-Jan.	0.08	0.07	0.08	0.09	0.10	0.12	0.32	0.36	0.38	0.42	0.45	0.51
Feb.	0.07	0.07	0.07	0.08	0.09	0.12	0.32	0.35	0.42	0.41	0.43	0.49
Mar.*	0.07	0.07	0.07	0.08	0.09	0.11	0.43	0.48	0.52	0.54	0.57	0.60
Weekly (Friday) average												
Mar. 6	0.07	0.07	0.07	0.07	0.08	0.10	0.40	0.43	0.46	0.48	0.53	0.55

Period	AA nonfinancial						A2/P2 nonfinancial					
	1-day	7-day	15-day	30-day	60-day	90-day	1-day	7-day	15-day	30-day	60-day	90-day
Mar. 13	0.07	0.07	0.08	0.08	0.09	0.11	0.42	0.48	0.54	0.54	0.59	0.58
Mar. 20	0.08	0.07	0.07	0.09	0.08	n.a.	0.47	0.50	0.54	0.59	0.60	0.64
Mar. 27	0.07	0.07	0.07	0.09	0.09	0.10	0.43	0.50	0.52	0.56	0.60	0.67
Apr. 3*	0.07	0.03	0.06	0.07	0.10	n.a.	0.43	0.51	0.53	0.51	0.52	0.53
Daily												
Mar. 25	0.08	0.07	0.07	0.08	0.08	0.09	0.43	0.52	0.49	0.53	0.60	0.67
Mar. 26	0.08	0.06	0.06	0.09	0.11	0.13	0.41	0.48	0.52	0.55	0.58	n.a.
Mar. 27	0.07	n.a.	0.08	0.09	0.10	0.10	0.41	0.48	0.54	0.56	0.62	n.a.
Mar. 30	0.07	0.01	0.06	0.08	0.11	n.a.	0.41	0.55	0.56	0.52	0.53	n.a.
Mar. 31	0.07	0.04	0.06	0.06	0.08	n.a.	0.44	0.46	0.49	0.49	0.51	0.53

* Data through March 31.
Note: n.a. indicates that trade data was insufficient to support calculation of the particular rate.

Period	AA financial						AA asset-backed					
	1-day	7-day	15-day	30-day	60-day	90-day	1-day	7-day	15-day	30-day	60-day	90-day
Annual average												
2013	0.07	0.07	0.07	0.09	0.11	0.14	0.14	0.18	0.18	0.17	0.20	0.22
2014	0.06	0.07	0.07	0.08	0.10	0.12	0.11	0.12	0.13	0.15	0.18	0.20
2015*	0.08	0.08	0.09	0.10	0.13	0.15	0.13	0.14	0.15	0.16	0.19	0.22
Monthly average												

Period	AA financial						AA asset-backed					
	1-day	7-day	15-day	30-day	60-day	90-day	1-day	7-day	15-day	30-day	60-day	90-day
2014-Oct.	0.06	0.07	0.07	0.08	0.10	0.12	0.12	0.12	0.13	0.14	0.18	0.20
Nov.	0.07	0.08	0.08	0.09	0.11	0.13	0.12	0.12	0.13	0.15	0.17	0.20
Dec.	0.10	0.10	0.09	0.11	0.14	0.15	0.14	0.13	0.15	0.16	0.19	0.21
2015-Jan.	0.08	0.09	0.10	0.12	0.14	0.16	0.14	0.13	0.15	0.16	0.20	0.23
Feb.	0.08	0.08	0.08	0.10	0.12	0.15	0.13	0.13	0.14	0.16	0.19	0.22
Mar.*	0.08	0.08	0.08	0.09	0.12	0.14	0.14	0.14	0.15	0.16	0.20	0.22
Weekly (Friday) average												
Mar. 6	0.08	0.08	0.08	0.09	0.11	0.14	0.13	0.14	0.15	0.17	0.19	0.21
Mar. 13	0.08	0.08	0.09	0.10	0.14	0.14	0.13	0.14	0.15	0.16	0.20	0.23
Mar. 20	0.08	0.08	0.08	0.09	0.11	0.14	0.15	0.13	0.16	0.16	0.20	0.22
Mar. 27	0.08	0.08	0.09	0.09	0.12	0.16	0.15	0.14	0.14	0.16	0.19	0.22
Apr. 3*	0.09	n.a.	0.08	n.a.	0.13	0.16	0.13	0.13	0.16	0.17	0.19	0.20
Daily												
Mar. 25	0.08	0.08	0.08	0.09	0.11	0.14	0.15	0.13	0.12	0.15	0.19	0.24
Mar. 26	0.09	0.09	0.10	n.a.	0.17	0.20	0.16	0.13	0.14	0.17	0.18	0.20
Mar. 27	0.09	n.a.	0.09	0.09	0.12	0.15	0.15	0.14	0.14	0.16	0.19	0.20
Mar. 30	0.09	n.a.	0.08	n.a.	n.a.	n.a.	0.13	0.13	0.14	0.17	0.18	0.19
Mar. 31	0.09	n.a.	0.08	n.a.	0.13	0.16	0.12	0.13	0.17	0.16	0.19	0.21

* Data through March 31.

Note: n.a. indicates that trade data was insufficient to support calculation of the particular rate.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2014-00371**

In Re the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

REBUTTAL TESTIMONY OF
JOHN P. MALLOY
VICE PRESIDENT, CUSTOMER SERVICES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Dated: April 14, 2015

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

A. My name is John P. Malloy. I am the Vice President, Customer Services 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. Please describe your educational and professional background.

A. A statement of my professional history and education is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before the Commission previously, including supplying pre-filed direct testimony.[1] I have also sponsored responses to data requests in numerous Commission cases, including a number of data requests in these proceedings.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to certain of the arguments presented in the testimonies of Dr. Paul A. Coomes on behalf of Kentucky Industrial Utility Customers, Inc. ("KIUC"), Steve W. Chriss on behalf of Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"), Ronald L. Willhite on behalf of Kentucky School Boards Association ("KSBA"), Malcolm J. Ratchford on behalf of Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC"), and Marlon Cummings on behalf of Association of Community Ministries, Inc. ("ACM").

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[1] *See In the Matter of: The Application of Kentucky Utilities Company to Modify Certain Certificates of Public Convenience and Necessity to Construct Ductwork for Two Flue Gas Desulfurization Units at the Ghent Power Station*, Case No. 2006-00493, Direct Testimony of John P. Malloy (Nov. 16, 2006).

Specifically, I will address concerns relating to (1) the Companies' customer-classification process for Demand-Side Management ("DSM") purposes, (2) KSBA's School Energy Management Program, (3) KU's All-Electric School Service ("Rate AES"), (4) the Companies' proposed rates' effect on low-income customers, (5) the Companies' procedures regarding service disconnections and reconnections, (6) the Companies' request to increase residential customer-deposit amounts, (7) the Companies' request to allow disconnection notices to be sent by electronic mail upon request by a customer, and (8) the importance of export-based industries.

The Companies' Customer Classifications for DSM Purposes Use Both Tariffed Criteria and Are Reasonable

Q. What criteria do the Companies use to determine which customer contracts to classify as industrial for DSM purposes?

A. As Robert M. Conroy discusses at greater length in his rebuttal testimony, the Companies' tariffs provide two criteria for the Companies to use when determining whether to classify a customer contract as industrial for DSM purposes:

> [N]on-residential customers will be considered "industrial" if [1] they are primarily engaged in a process or processes that create or change raw or unfinished materials into another form or product, and/or [2] in accordance with the North American Industry Classification System, Sections 21, 22, 31, 32, and 33. All other nonresidential customers will be defined as "commercial."[2]

[2] Kentucky Utilities Company P.S.C. No. 16, First Revision of Original Sheet No. 86; Louisville Gas and Electric Company, P.S.C. Electric No. 9, First Revision of Original Sheet No. 86. LG&E's gas tariff explicitly refers to the definition of "industrial" in LG&E's electric tariff, and is therefore the same: "Any industrial gas customer who also receives electric service from the Company as an industrial customer, and has elected not to participate in a demand-side management program hereunder, shall not be assessed a charge pursuant to this mechanism." Louisville Gas and Electric Company, P.S.C. Gas No. 9, First Revision of Original Sheet No. 86.

Mr. Chriss's testimony on behalf of Wal-Mart briefly acknowledges that the Companies' tariffs contain two criteria,[3] but then dedicates the rest of his DSM-related testimony to attacking only the Companies' use of North American Industry Classification System ("NAICS") codes. Moreover, Mr. Chriss states later in his testimony that the Companies' tariffs define "industrial" for DSM purposes "per the use of the specific NAICS codes,"[4] without mentioning the Companies' use of the criterion whether a customer contract applies to "a process or processes that create or change raw or unfinished materials into another form or product …." As the Companies' officer responsible for implementing the Companies' tariffs in this regard, I can assure the Commission that the Companies use both tariffed criteria when determining whether a customer contract is industrial for DSM purposes.

Q. What is an NAICS code?

A. According to the federal government, which creates NAICS codes, "The North American Industry Classification System (NAICS) is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy."[5] Two-digit NAICS sector codes, like those used in the Companies' tariffs, identify broad types of economic activity in which businesses engage. For example, NAICS sector code 22 applies to all utilities. So NAICS codes, particularly at the sector level, are a means of identifying the primary kind of economic activity in which a business engages.

[3] Direct Testimony and Exhibits of Steve W. Chriss on Behalf of Wal-Mart ("Chriss Testimony") at 19 (KU) and 17 (LG&E).
[4] Chriss KU Testimony at 21; Chriss LG&E Testimony at 19.
[5] http://www.census.gov/eos/www/naics/ (viewed on March 25, 2015).

Q. Do the Companies use only a business entity's NAICS code to determine if all of the business's contracts with LG&E or KU should be classified as industrial for DSM purposes?

A. No. By their nature, NAICS codes, and particularly two-digit NAICS sector codes, cannot identify the primary purpose of each utility-service installation provided to a business entity. Moreover, consistent with the federal government's approach, the Companies apply NAICS codes to business entities; the Companies do not attempt to assign unique NAICS codes to contracts for individual utility-service installations, which would be inconsistent with the purpose of NAICS codes.

Recognizing that a business entity, even one "primarily engaged in a process or processes that create or change raw or unfinished materials into another form or product," can have locations that have primary functions other than what the business entity's NAICS code would indicate, the Companies use a business entity's NAICS code to inform their DSM classification decision for each of the business's contracts, but the NAICS code alone does not dictate whether the Companies will classify a customer as industrial for DSM purposes.

Q. How did the Companies' recent data and business-process review of contract classifications for DSM purposes show that the Companies do not use only NAICS codes to classify contracts?

A. The Companies recently conducted a thorough review of their current data concerning all metered non-residential customer contracts to verify the classification of contracts as industrial or commercial. As the Companies described in the supplemental responses to data requests from the Commission, the Companies' verification process used business customers' NAICS codes (where available) only to apply a presumption for or against classifying a customer as industrial for DSM purposes; for all contracts, the Companies' ultimate classification relied upon at least one other data point to indicate that the contract either did or did not serve "a process or processes that create or change raw or unfinished materials into another form or product …."[6] So the verification process required applying both tariffed criteria to each contract, not only NAICS codes.

Having now completed the verification process (subject to possible additional site visits to confirm the Companies' classifications for some customers), the Companies have classified a total of 2,320 contracts as industrial for DSM purposes (1,417 for KU, 671 for LG&E electric, 232 for LG&E gas). Of those contracts, 125 are associated with customers that either do not have an NAICS code the Companies could locate or have an NAICS code other than one of the five listed in the Companies' tariffs. Those 125 contracts are not misclassified; rather, they show that NAICS codes alone do not determine a customer contract's classification for DSM purposes.

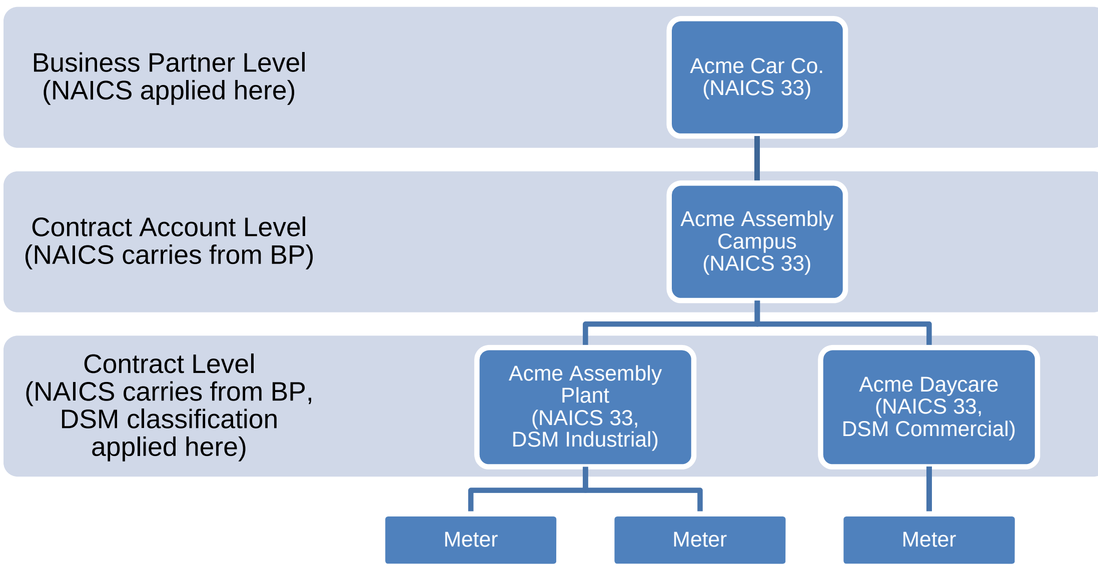
Q. Can you give an example of a how a contract could be associated with an industrial NAICS code yet be classified as commercial for DSM purposes?

A. Yes. Consider an automobile manufacturer (Acme Car Company) with an assembly campus that includes a large car assembly plant and a separate company-owned daycare center for assembly-plant employees. As a company, Acme likely would have NAICS sector code 33, one of the five NAICS codes listed in the Companies' DSM tariff sheets. For the assembly campus, Acme would likely have two contracts for service with either LG&E or KU, one for the assembly plant and the other for the daycare center. Applying

[6] *See* LG&E Supplemental Response to PSC 2-71; LG&E Second Supplemental Response to PSC 3-22; KU Supplemental Response to PSC 2-62; KU Second Supplemental Response to PSC 3-15.

the Companies' first tariff criterion, the assembly plant clearly "primarily engage[s] in a process or processes that create or change raw or unfinished materials into another form or product," and therefore would be classified as industrial for DSM purposes. But the Acme daycare center, even though it is associated with Acme's NAICS code, clearly does not meet the first criterion, and would be classified as commercial for DSM purposes.

The following diagram illustrates this example:



Q. Do you have any concluding remarks on this issue?

A. Yes. The Companies' data show that they have applied both of their tariffed criteria in practice when classifying customer as industrial or commercial for DSM purposes. Therefore, Mr. Chriss's testimony is simply incorrect to the extent it states or implies that the Companies use only NAICS codes to classify customers for DSM purposes.

KSBA's School Energy Management Program

Q. How are the Companies involved in KSBA's School Energy Management Program?

A. KSBA's School Energy Management Program ("SEMP") was initiated in 2010 to aid the development of energy-efficiency practices in public schools.[7] The Companies agreed, as part of the settlement agreement in their 2012 rate cases, to propose a two-year DSM program to help fund SEMP.[8] On an annual basis, KU agreed to provide $500,000 and LG&E agreed to provide $225,000, a total of $1,450,000 for the two-year period.[9] The funds were intended to facilitate the hiring and retention of energy specialists by public school districts.[10] Of the $1,450,000 the Companies agreed to provide for SEMP, KSBA submitted requests for only $975,000, all of which the Companies supplied as requested.[11]

Q. Are the Companies requesting Commission approval to extend the School Energy Management Program?

A. No, not at this time. The Companies' SEMP funding was approved for a two-year period with no expectation that it would continue beyond the initial approval cycle; the Companies stated in the record of the proceeding seeking approval for the two-year DSM funding of SEMP, "[T]he Companies are supporting the Energy Management Program for Schools for only the two years referenced in the agreement."[12] Mr. Willhite's testimony in these proceedings expresses KSBA's desire for the Companies to request Commission approval to extend the DSM funding of the SEMP.[13] Also, as a longstanding member of the

[7] *See* Direct Testimony of Ronald L. Willhite on Behalf of the KSBA ("Willhite Testimony") at 5 (KU and LG&E).
[8] *See In the Matter of: the Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for the Review and Approval of a Two-Year Demand Side Management Program Related to School Energy Management and Associated Cost,* Case No. 2013-00067, Application at 4 (Feb. 20, 2013).
[9] *Id.* at 5.
[10] *Id.* at 5.
[11] See KSBA's Response to KU DR 1; KSBA's Response to LG&E DR 1.
[12] *See* Case No. 2013-00067, Response to Commission Staff's First Request of Information, Question 7.
[13] *See* Willhite KU Testimony at 8; Willhite LG&E Testimony at 8.

Companies' DSM Advisory Group—a group that was involved in helping to shape the Companies' recently approved 2015-2018 DSM-EE Program Plan—KSBA is welcome to raise this issue at Advisory Group meetings. But the Companies are not presently proposing to extend their SEMP funding beyond the two years currently approved.

<u>KSBA's Asserted Billing Errors under KU's Rate AES Are Incorrect</u>

Q. Are you aware of any schools KU serves that are entitled to refunds for service taken under a "wrong rate"?

A. No. Contrary to Mr. Willhite's assertion, at no time did any school take service under the "wrong rate."[14] When more than one Commission-approved rate is available to any customer, including schools, KU's tariff provides that it is the customer's duty to select the rate under which it desires service; KU may not make that determination absent a customer's request and customers are not entitled to a refund if they later realize they could have taken service under a more financially advantageous rate.[15] These provisions are supported by Commission precedent,[16] as well as at least one long-standing opinion of Kentucky's highest court.[17] It is therefore important to note that Mr. Willhite's testimony does not provide evidence that any school took service from KU under a truly "wrong rate"; rather, the testimony only contains assertions some schools took service under a rate less financially advantageous than KU's Rate AES.

Q. Has KU provided refunds to a small number of schools served under Rate AES?

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[14] *See* Willhite KU Testimony at 14.
[15] Kentucky Utilities Company P.S.C. No. 16, Original Sheet Nos. 97 to 97.1.
[16] *See, e.g., In the Matter of: Hart County Bank and Trust Company v. Kentucky Utilities Company,* Case No. 2014-00331, Order (Feb. 2, 2015).
[17] *Southeastern Land Co. v. Louisville Gas & Electric Co.,* 90 S.W.2d 1, 11 (Ky. 1936), *quoting Spear & Co. v. Public Service Commission*, 161 A. 441 (Pa. Super. Ct. 1932).

A. Yes. Consistent with KU's Commission-approved tariff, KU has provided a small number of schools refunds because the schools or the Companies sufficiently established through documentation that the schools had requested service under Rate AES and KU had continued billing the schools under other rates for which the schools were eligible. KU informed KSBA that if schools previously qualified for Rate AES and evidenced the fact they had asked for service on Rate AES, KU would move the school to Rate AES and provide a refund back to the date of the initial request, up to five years in accordance with KU's tariff. To the best of KU's knowledge, all of the schools that have made the requisite showing have received refunds. Though other schools have requested refunds, they have not provided sufficient documentation, and KU has been unable to find any documentation, to support an assertion that they had previously asked KU to provide service under Rate AES.

Q. May KU provide refunds to schools now taking service under Rate AES that have not made the requisite showing that they had previously qualified for and requested service under Rate AES (while Rate AES was open for new customers)?

A. No, KU cannot provide refunds to such customers. KSBA suggests that KU should make refunds when it was aware a school was all-electric and did not place the school on Rate AES.[18] But providing refunds under these circumstances, i.e., where a school did not expressly request service under Rate AES, would violate KU's Commission-approved tariff, which states that it is a customer's duty, not KU's, to choose between optional rates.[19] Therefore, KU is obligated to deny KSBA's refund request because KU may not deviate

[18] *See* Willhite KU Testimony at 14.
[19] Kentucky Utilities Company P.S.C. No. 16, Original Sheet Nos. 97 to 97.1.

from its Commission-approved tariff; doing so would violate the filed-rate doctrine,[20] which the Commission has stated is the "bedrock of utility regulation."[21]

Q. Does KU have readily available to it information indicating whether a school is all-electric?

A. No, not until a school requests service under Rate AES (which is no longer possible, because the rate schedule has been closed since 2010). Notwithstanding a customer's express duty to choose between optional rates, and KU's express duty not to provide refunds when a customer fails to select the most financially advantageous rate, KSBA misstates KU's knowledge of whether a school is all-electric. KSBA claims, "KU was fully aware when a school was all-electric as KU provides the secondary line [for schools on Rate AES] whereas the school is required to provide the secondary line for any non all-electric school served on Rate PS and TODS."[22] KSBA makes this claim based on a KU data response indicating that customers served under Rate AES receive service from a secondary line owned by KU.[23]

That KU serves all-electric schools taking service on Rate AES via a company-supplied secondary line does not mean that KU knows whether each and every school is all-electric. Some schools take service under KU's General Service Rate Schedule ("Rate GS"). Like all-electric schools served under Rate AES, customers on Rate GS also take service via a company-supplied secondary line; thus, service via a company-supplied line in no way indicates to KU whether the customer is all-electric.

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[20] *Keogh v. Chicago & Northwestern Ry.*, 260 U.S. 156, 163 (1922); *See also* Case No. 95-107, Order at 3 (Oct. 13, 1995).
[21] Case No. 95-107, Order at 2.
[22] *See* Direct Testimony of Ronald L. Willhite at 14.
[23] *See* KU Response to KSBA First Request of Information, No. 8.

Moreover, regarding schools taking service under Rate PS and TODS, KSBA fails to acknowledge an important distinction between all-electric schools and all-electric schools that take service under Rate AES; i.e., not every all-electric school takes service under Rate AES (or Rate GS). Therefore, not every all-electric school takes service via a company-supplied secondary line. Because some all-electric schools also take service under Rate PS or TODS (or Rate GS), KU has no way of knowing if a school is all-electric unless and until the school requests service under Rate AES; if KU grants the request, the school will begin taking service from a secondary line owned by KU (if it is already by virtue of taking service under Rate GS). But if an all-electric school does not request service under Rate AES, or if KU is not able to grant a request for service under Rate AES, the school will continue to take service from a secondary line owned by the school (if it is currently taking service under Rate PS or TODS). KU has no other way of knowing whether or not a school is all-electric; it is the customer, not the utility, who understands their usage and facilities best, which is exactly why it is the customer's, and not the utility's, obligation to indicate under which rate it desires service if more than one is available.

<u>The Companies Are Mindful of Increased Rates' Effects on Low-Income Customers, but the Proposed Increases Are Necessary to Ensure Continued Safe and Reliable Service at the Lowest Reasonable Cost</u>

Q. Do the Companies consider the effect higher rates have on their fixed- and low-income customers?

A. Yes. Mr. Staffieri stated in his direct testimony that the Companies take very seriously the decision to increase rates.[24] The Companies are well aware of the financial hardships faced by many of their customers and strive to ensure that these customers receive low-cost

[24] *See* Direct Testimony of Victor A. Staffieri at 8.

energy; moreover, the Companies strive to provide sufficient energy-assistance resources when needed. But the Companies must also ensure that their customers receive reliable, safe service; doing so requires constant investment and improvement, thereby necessitating the requested increase. CAC recommends that the Commission approve the lowest possible rate increase,[25] but the Companies firmly believe their proposal will result in safe, reliable service at the lowest reasonable cost.

Q. Do you agree with CAC's claim regarding the increased rates and the lack of sufficient energy-assistance resources?[26]

A. No, I do not. The Companies' decision to request rate increases does not mean they are unaware of or do not appreciate the circumstances their customers face. Mr. Staton's direct testimony provides detailed information about the Companies' significant assistance to low-income customers in the form of shareholder contributions to energy-assistance funds, participation in winter-weatherization efforts, and development of a robust DSM portfolio with programs specifically aimed at low-income customers.[27] For example, the Companies' Low-Income Weatherization Program ("WeCare") is an education and weatherization program designed to reduce the energy consumption of the Companies' low-income customers.[28] The program provides energy audits, energy education, and blower door tests, installs weatherization and energy conservation measures, and is now the Companies' second largest DSM program by budget: over $25.5 million total for both Companies for program years 2015-2018.[29]

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[25] Direct Testimony of Malcolm J. Ratchford at 19.
[26] *Id.* at 18.
[27] *See* Direct Testimony of Edwin R. "Ed" Staton at 5-11.
[28] *Id.* at 9.
[29] *Id.*

Those are just a few of the many ways the Companies strive to ensure that all their customers receive low-cost, reliable utility service. In addition, the Companies' FLEX programs allow residential customers with limited incomes to pay their bills 28 days from issuance, thereby helping to prevent fixed- and low-income customers from incurring late payment charges, increasing the time in which customers can seek financial aid, and reducing the number of disconnections.[30]

In light of Companies' efforts to assist fixed- and low-income customers, CAC's assertion that energy-assistance resources are lacking should in no way indicate that the Companies are not doing their part to help customers with limited means. For example, the CAC requests that KU increase its Home Energy Assistance ("HEA") Program efforts;[31] but the Companies have actually provided energy-assistance funding in amounts greater than CAC and other low-income advocates have been able to use. In October 2014, LG&E's HEA Program had a balance of over $600,000 and KU's HEA Program had a balance just under $500,000.[32] Regarding shareholder contributions to the HEA, Wintercare, and utility-assistance programs, which are set to expire upon the effective date of the new base rates proposed in this proceeding,[33] the Companies hope the parties to this proceeding come to an amicable solution. In addition, although the Companies maintain discretion to discontinue or reduce the monthly residential HEA charge, the Companies propose to continue the charge at $0.25 per meter, the same amount currently charged under their tariffs.[34]

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[30] *Id.* at 8.
[31] *See* Direct Testimony of Malcolm J. Ratchford at 19.
[32] *See* Case No. 2007-00337, LG&E and KU HEA Report at 4 and 12 (March 13, 2015).
[33] *See* Direct Testimony of Edwin R. "Ed" Staton at 7.
[34] *Id.*

<u>LG&E's Service Disconnection and Reconnection Data Are Not Cause for Concern</u>

Q. Have LG&E's numbers of service disconnections changed significantly in the last few years?

A. No, they have not. LG&E provides annual disconnection reports to the Commission, each of which addresses twelve months from July of one calendar year through June of the next. The most recent three years of data (2011-2012, 2012-2013, and 2013-2014) show that LG&E's disconnections of combined electric and gas customers and electric-only customers have increased by only 3% (from 62,088 to 64,252), and that LG&E's disconnections of gas-only customers have decreased by 7% (from 2,718 to 2,539).

In contrast, Mr. Cummings's testimony compares data from the 2009-2010 report to the 2013-2014 report and states that LG&E's disconnections of combined electric and gas customers and electric-only customers have increased 31% and that gas-only disconnections have increased 15%.[35] Although true, these numbers are misleading because two extraordinary circumstances in 2009-2010 and 2010-2011 affected LG&E's number of disconnections. First, a severe and highly damaging ice storm occurred in the western KU and LG&E service territories areas in early 2009; related repairs decreased resources available to disconnect service well into the 2009-2010 year, and the Companies decreased disconnections to aid customers during harsh winter weather. Second, to prepare for the April 2009 live implementation of the Companies' new Customer Care System, an entirely new computer system reaching all areas of the Companies' operations, the Companies ceased disconnecting service in March 2009. The Companies did not resume disconnections in earnest until early summer 2009, and disconnection levels were lower

[35] Cummings Testimony at 9-10.

than normal until full account dunning was completed the second half of 2011, all to ensure customers were not disconnected in error. Therefore, although LG&E does not dispute Mr. Cummings's calculations comparing 2009-2010 to 2013-2014, the comparison is misleading. Comparing more recent years' data shows LG&E's numbers of disconnections have not markedly changed.

Q. Have LG&E's overall numbers of service reconnections recently decreased? If so, is it a cause for concern?

A. As Mr. Cummings testifies,[36] LG&E's overall number of service reconnections has recently decreased, but the Companies do not believe this is a cause for concern for several reasons. First, customers who have service disconnected for non-payment at one premise sometimes move to another premise and begin new service there, whether inside or outside the serving utility's service territory. This would result in a service disconnection without a corresponding reconnection. Second, in a residence where multiple adults reside, service to the premise may be disconnected for non-payment under one resident's name and soon thereafter reinitiated under another resident's name. This, too, would result in a service disconnection without a corresponding reconnection. Third, some customers may find that their overall cost of living would decrease by moving in with a relative or friend, which again could result in a service disconnection without a corresponding reconnection. None of these circumstances would be cause for concern.

Additional data tend to indicate that the three circumstances discussed are actually driving the apparent difference between numbers of disconnections and reconnections. Notably, although combined electric and gas disconnections and electric-only

[36] Cummings Testimony at 10.

disconnections have exceeded reconnections by a total of 9,528 from 2011 through 2013 in the zip codes identified by Mr. Cummings,[37] LG&E's total number of active combined electric and gas customers and electric-only customers in the same zip codes over the same time has decreased by only 777. During the same time period, LG&E's total number of active combined electric and gas customers and electric-only customers in Jefferson County increased by 4,388. These data points tend to indicate that the difference between disconnections and reconnections Mr. Cummings identifies likely arises not from large numbers of people going without utility service, but rather from the three causes I discussed above that do not give reason for concern.

Q. Has LG&E changed in any way its Winter Hardship Reconnection process in recent years?

A. No, both Companies have had in recent years the same Commission-regulation-compliant Winter Hardship Reconnection process they have had for many years; nothing has changed. As required by 807 KAR 5:006 Section 16, a customer disconnected for nonpayment can apply to obtain a winter-hardship reconnection by presenting a Certificate of Need, paying one-third of the outstanding bill or $200, whichever is less, and agreeing to a repayment schedule to bring the customer current. Again, these are regulatory requirements, requirements with which LG&E continues to comply.

Q. Do you agree with ACM's concerns regarding the Companies' winter-hardship reconnection process?[38]

A. No, I do not. As I testified above, the Companies' winter-hardship reconnection process has not changed; it is as available to customers now as it has always been. But a likely

[37] Cummings Testimony at

[38] *See* Direct Testimony of Marlon Cummings on Behalf of the ACM at 16.

contributing factor to the decrease in winter-hardship reconnections in 2014 is that the Companies relaxed their installment-plan parameters in early 2014 due to the extremely cold winter, resulting in substantially increased installment plans and a reduced need for winter-hardship reconnections in 2014:

Year	Number of Installment Plans	Change Year over Year
2011	167,076	N/A
2012	185,614	18,538
2013	185,617	3
2014	239,157	53,540

Finally, recognizing the severity of the recent cold, the Companies voluntarily suspended conducting disconnections for 25 business days in January through March of 2015 to allow customers more time to pay their bills or arrange installment plans and to ensure customers kept service during the most severe cold.

<u>The Companies' Proposed Increased Residential Customer Deposits Are Reasonable</u>

Q. Why are the Companies' proposed increased residential customer deposits reasonable, particularly for low-income customers?

A. The Companies understand the view Mr. Cummings's testimony expresses concerning the Companies' proposal to increase residential customer deposits.[39] Certainly it is not the Companies' desire, or even in their interest, to raise barriers to customers' taking service. But customer deposits are an integral to ensuring payment for services, and they protect all customers. When customers fail to pay their utility bills, the resulting uncollectible-debt expenses eventually increase rates for all customers through eventual base-rate adjustments. The resulting rate increases presumably would have the most damaging impact on the same low-income customers for which Mr. Cummings advocates. The

[39] Cummings Testimony at 17.

Commission's regulations therefore wisely and expressly allow utilities to establish customer-deposit requirements,[40] which help ensure that at least a portion of bad-debt expenses can be covered, thereby alleviating some of the negative effect caused by non-payments.

The particular deposits the Companies are proposing in these proceedings--$160.00 for electric-only customers and $260.00 for combined electric and gas customers—are entirely reasonable. As Mr. Conroy's direct testimony states, these amounts are well less than the 2/12 of an average customer's annual usage would justify.[41] Because the Companies' proposed deposits are based on average customer bills, the proposed deposits are actually particularly favorable for customers who typically have above-average bills, as many low-income customers do.[42]

Moreover, the Companies' proposed deposits are substantially less than the actual arrearages of customers whose service the Companies disconnect for non-payment. In 2014, the average residential customer disconnected for non-payment in KU's service territory had an arrearage of $194; for LG&E electric-only customers, the comparable amount was $218, and for combined electric and gas customers, the comparable amount was $385 at the time of the issuance of the disconnect notice to the customer. Therefore, although the Companies' proposed deposits will help reduce the impact of non-payments, they will not come close to offsetting it entirely.

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[40] 807 KAR 5:006 Section 8(1)(a).
[41] Conroy KU Testimony at 34; Conroy LG&E Testimony at 41.
[42] *See* Companies' Response to KU Sierra Club 2-4; Companies' Response to LG&E Sierra Club 2-4. These responses show that a majority of KU's low-income customers have above-average usage (14,545 of a total 28,031 low-income customers), and that a significant minority of LG&E's low-income customers have above-average usage (8,368 of a total 20,437 low-income customers). In those responses, "low-income" is defined as "residential customers who received assistance from a third-party agency in 2013."

Again, the Companies' proposed residential customer deposits comply with the Commission's regulations and are reasonable and necessary to help reduce the impact on all customers from bad-debt expenses.

<u>The Companies' Proposal to Send Notice of Service Disconnection by Electronic Mail Will Benefit Customers</u>

Q. How will the Companies' proposal to send notices of service disconnection by electronic mail benefit customers?

A. The Companies are proposing that customers will have the option to receive notices of pending service disconnection, also known as brown bills, by electronic mail instead of, or in addition to, receiving notice in paper form; the choice will be entirely the customer's to make using the Companies' website, and customers who do not select either option will continue to receive notices of pending service disconnection solely by paper mail, just as they do today. This proposal is part of the Companies' ongoing efforts to enhance customer service and communicate with customers using whatever media are most convenient for them; again, whether to receive pending service disconnection notices through e-mail only, e-mail and paper, or paper only will be entirely and solely the customer's choice. Although the Companies are aware that not all customers have ready access to e-mail, as Mr. Cummings notes in his testimony,[43] the Companies have many customers who do have such access and who might prefer to receive such communications through e-mail instead of, or in addition to, conventional paper mail. The Companies believe providing this form of notice to customers who choose to receive it will help ensure they have ample opportunity to contact the Companies to make other arrangements, i.e., installment plans,

[43] *See* Direct Testimony of Marlon Cummings on Behalf of the ACM at 17-18.

to avoid a service disconnection, allowing such customers to continue their service without interruption.

Q. If a customer chooses to receive e-mail brown bills only, will the customer receive a paper brown bill if the Companies receive notice that the e-mail could not be delivered?

A. Yes. One of the advantages of e-mail is that the Companies can receive automated notices that an e-mail brown bill was unable to be delivered (i.e., the e-mail bounces back). Upon receiving such a notice, the Companies would send the affected customer a paper brown bill. Again, the Companies' goal is to provide customers notice that is consistent with the applicable regulation, 807 KAR 5:006 Sec. 15, using media customers choose as most convenient for them.

<u>The Importance of Export-Based Industries</u>

Q. Briefly explain KIUC's position regarding the importance of export-based industries.

A. Dr. Coomes on behalf of KIUC provided testimony asserting that "the most important industries, in terms of economic growth, are those that export goods and services to customers around the US and the world."[44] Dr. Coomes explains that these industries are highly valued primarily because they are employment multipliers and add dollars to the local economy.[45] According to Dr. Coomes, Kentucky's low-cost electricity has been one of the primary factors attracting these industries to the Commonwealth.[46] Dr. Coomes does not make a specific recommendation about the Companies' requested rate increase; rather,

[44] *See* Direct Testimony and Exhibits of Paul A. Coomes on Behalf of KIUC at 2.
[45] *Id.* at 3-4.
[46] *Id.* at 5-7.

Dr. Coomes asserts the Commission should consider the economic effect that a rate increase may have on export-based industries.[47]

Q. Do you agree that export-based industries are important to Kentucky's economy?

A. Yes, and the Companies have the privilege of serving a significant number of such customers. The Companies believe the best way to serve all customers, large and small, is to continue to provide safe and reliable service at the lowest reasonable cost, and to design rates to reflect the Companies' cost of service.

Q. Does this conclude your testimony?

A. Yes, it does.

[47] *Id.* at 7.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John P. Malloy**, being duly sworn, deposes and says that he is Vice President, Customer Services 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.

John P. Malloy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 14th day of April 2015.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

APPENDIX A

John P. Malloy

Vice President, Customer Services
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202

Work History

Vice President, Customer Services (LG&E and KU Services Company)	2007-present
Director - Generation Services (E.ON U.S. Services Inc.)	2003 - 2007
Maintenance Manager, Mill Creek (LG&E)	1998-2003
Manager Resource / Project Management – Fleet (LG&E)	1996-1998
Instrument and Electrical Supervisor, Mill Creek (LG&E)	1989-1996
Instrument and Electrical Technician, Mill Creek (LG&E)	1986-1989
Production Operations, Mill Creek (LG&E)	1984-1986
Coal Handling Operations, Cane Run (LG&E)	1983-1984
Instrument and Electrical Technician, Cane Run (LG&E)	1980-1983

Education

Indiana University, Master Business Administration	2000
Indiana University, B.S. in Finance	1998

Other Professional Associations

LG&E Credit Union	
Chairman, Board of Directors	2001- 2007
Treasurer, Board of Directors	1998-2001
Board of Directors	1995-1998

Community Service

Kentucky Association of Manufacturers – Executive Board	2010 – current
Boy Scouts of America – Executive Board, Finance Chairman	2005 – current
Louisville Orchestra – Executive Board	2007 – current
Ronald McDonald House Charities – Board	2014 – current
Leadership Kentucky – Board	2009 – current

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2014-00371**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

REBUTTAL TESTIMONY OF
DAVID S. SINCLAIR
VICE PRESIDENT, ENERGY SUPPLY AND ANALYSIS
LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Filed: April 14, 2015

Table of Contents

<u>Section 1 – Introduction and Overview</u>

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

A. My name is David S. Sinclair. I am Vice President, Energy Supply and Analysis for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies") and an employee of LG&E and KU Services Company. 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 issues related to: (1) the Curtailable Service Rider ("CSR") raised by Kentucky Industrial Utility Customers, Inc. ("KIUC") witnesses Stephen J. Baron and Mary Jean Riley; (2) the concept of an Off-System Sales ("OSS") Tracker raised by KIUC witness Lane Kollen and Attorney General ("AG") witness Frank W. Radigan; and (3) the impact of the Basic Service Charge on the demand for electricity and on low-income customers raised by Sierra Club witness Paul Chernick and Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC") witness Malcolm J. Ratchford.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibit to my rebuttal testimony:

Rebuttal Exhibit DSS-1 2015 KU Rate Assessment for All-Electric KU Customers Receiving Third Party Assistance

<u>Section 2 – Curtailable Service Rider</u>

Q. Do you agree with KIUC witness Mr. Baron that the Companies treat CSR load reductions as equivalent to supply side resources from a long-term planning perspective?[1]

A. Yes. The Companies' long-term capacity and system planning models assume that CSR load reductions are available to reduce system peak demand for the highest 100 load hours of the year. In these models, the CSR "resource" is assumed to be deployed after all available generation resources are committed and before any energy is purchased at a price greater than the highest cost unit.

Q. In the last few years, approximately how many times have system peak conditions occurred?

A. The last two winters have seen the Companies set numerous peak and daily energy records. For example, on January 6, 2014, the Companies set a record winter peak of 7,114 MW and came very close to meeting that on February 20, 2015 with a peak demand of 7,079 MW, a record peak for February. The Companies set a daily energy record on January 7, 2014 of 153,967 MWh. Since 2010, the Companies have also set monthly peak records for January, February, March, May, June, August, September, November, and December.

Q. During these peak events, do the Companies typically have all available generation committed to be able to meet load?

A. Yes.

Q. How many times have the Companies called upon CSR customers since 2013?

[1] Baron Testimony at 23 lines 3-11.

A. Since January 1, 2013, the Companies have asked for interruption three times, all in January 2014.

Q. During either of the winter peak events in January 2014 and 2015, did the Companies call upon CSR customers to physically curtail their load?

A. Yes. In 2014, the Companies called upon CSR customers to physically curtail during several hours on several different days during high load conditions. Most performed exactly or very nearly as requested. Unfortunately, several failed to completely meet their obligations to perform when called upon. This is not to impugn all CSR customers; as previously stated, most performed exactly or very nearly as requested. But it does demonstrate that CSR-curtailable load is not necessarily the same as utility-dispatchable generating resources, since the Companies do not operate or control the interruption activities.

Q. If the Companies generally commit all available generating resources during peak events, why did they only call on CSR customers occasionally despite setting so many monthly peak records in recent years?

A. The current CSR tariff limits the Companies' ability to ask for a physical curtailment to a "system reliability event."[2]

Q. How often do system reliability events occur?

A. Historically they have rarely occurred. The Companies work hard to plan and operate the system to avoid them because we know reliability is important to our customers.

Q. Are you familiar with Ms. Riley's testimony on behalf of North American Stainless ("NAS") concerning the Companies' proposed CSR tariff changes?

[2] See Standard Rate Rider Curtailable Service Rider – CSR10, Original Sheet No. 50 and Standard Rate Rider Curtailable Service Rider – CSR30, Original Sheet No. 51.

A. Yes. She objects to the Companies' proposal to eliminate the system reliability event restriction.[3]

Q. What is the basis for her objection to this change?

A. Ms. Riley states that should KU call upon NAS to interrupt up to 100 hours a year, it would create numerous economic and operational hardships for NAS.[4]

Q. Can KU guarantee that it will not have 100 hours of system reliability events during the course of a year?

A. No. While we work hard to plan and operate the system, there is no guarantee that such events will not occur.

Q. Are you the Companies' officer that is responsible for dispatching the generation fleet?

A. Yes. The Power Supply group reports to me and they have the responsibility for the various activities required to economically and reliably meet our customers' moment-to-moment electricity needs.

Q. Please describe the current daily process the Power Supply group goes through in order to ensure that adequate generation is available to meet customers' energy needs.

A. The Power Supply group is responsible for near term planning to ensure that resources are available to meet load. Closer to real time the following activities occur: forecast next-day and day-of load; evaluate available generation resources; determine need for contingency resources; commit resources to supply load (available generation and purchase power); and utilize contingency resources during real time events as they

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[3] Riley Testimony at 3-4.
[4] *Id.*

occur. CSR curtailable loads are not part of this planning process because the goal of this process is to avoid the very system reliability events that would permit the Companies to request physical curtailments from their CSR customers.

Q. So how would the decision to call for CSR customers to curtail their load fit into this process given the current limitation to system reliability events?

A. It is not a resource that will be part of the day ahead and same day planning. The Power Supply group will take all the appropriate actions to procure adequate resources to avoid system reliability events, including purchasing energy from others at prices that exceed the cost of our highest cost units. The Companies' purchasing activities in reality are different from the long-term modeling assumptions regarding CSR interruption where interruption is assumed to occur before the Companies would purchase expensive energy. This means that calling for a curtailment by CSR customers occurs only in real time to respond to unexpected events, such as losing generating capacity from several large units and being unable to procure energy from others to replace the lost capacity. In other words, the current CSR tariff terms, in effect, preclude the Companies from using CSR-curtailable load in the same way they use traditional supply side resources to help prevent a system reliability event from occurring; rather, CSR curtailments becomes an option only when maintaining system reliability is at risk.

Q. Given the current tariff restrictions relating to system reliability events, is the ability to curtail CSR customers really the same as the ability to call upon supply side peaking resources like simple cycle combustion turbines?

A. No. That is why the Companies are proposing to remove the system reliability event constraint in this rate case, so that the ability to call upon CSR load curtailment is similar, albeit with only 100 hours, to its ability to utilize its long-term supply side peaking resources.

Q. How often do the Companies operate their simple cycle combustion turbines?

A. From January 2013 through February 2015, the Companies generated 2.6 TWh from simple cycle combustion turbines in 6,936 hours, i.e., 37% of the time. The monthly percentage of hours with natural gas-fired generation has ranged between 11% and 96%, as shown in Table 1.

Table 1 – CT Operations

	Hours with CT Gen.	CT Energy (GWh)	% of Total Hours
January 2013	207	33.9	28%
February 2013	123	18.2	18%
March 2013	292	74.9	39%
April 2013	334	77.1	46%
May 2013	170	39.1	23%
June 2013	122	21.6	17%
July 2013	215	108.5	29%
August 2013	165	44.9	22%
September 2013	79	31.7	11%
October 2013	175	36.9	24%
November 2013	177	31.7	25%
December 2013	107	13.1	14%
January 2014	422	295.7	57%
February 2014	339	149.6	50%
March 2014	490	188.7	66%
April 2014	691	289.6	96%
May 2014	249	72.7	33%
June 2014	217	64.5	30%
July 2014	279	86.8	38%
August 2014	207	67.4	28%
September 2014	171	38.2	24%
October 2014	193	28.6	26%
November 2014	443	159.6	62%
December 2014	332	98.3	45%
January 2015	294	151.6	40%
February 2015	443	375.9	66%
Total	**6,936**	**2,598.9**	**37%**

Q. Are the Companies trying to be "punitive" toward CSR customers by eliminating the system reliability event limitation and buy-through provisions as implied by Mr. Baron?[5]

[5] Baron Testimony at 24 lines 12-20 and at 25 lines 1-11.

A. No. The Companies value their customers, and recognize the importance of their operations of their facilities and their interest in CSR optional rate schedules. The Companies also recognize that demand response programs like the CSR tariff can be least-cost resources, which is why the tariff is offered as an option for our customers. However, for a resource to be valuable for meeting load, it has to be available to do so. Based on the Companies' real-world experience in recent years, having a resource that is available only during system reliability events has limited value. Eliminating the system reliability event restriction simply puts the CSR resource on par with other peaking resources.

As to the elimination of the buy-through provision, the Companies viewed this as a benefit to CSR customers, not a punishment. The current buy-through provision does nothing to alter the Companies' resource planning or obligation to serve a CSR customer. It merely shifts fuel costs between CSR customers and non-CSR customers. The Companies are willing to reconsider their request to eliminate buy-through option in light of the CSR customers' view that the buy through option provides value by allowing the CSR customer to pay higher fuel costs in lieu of curtailment.

Q. The Companies' avoided cost of capacity cited by Mr. Baron is $100/kW-year. Do you agree with that value?[6]

A. Yes. That value is based on the levelized annual capacity cost of a new simple cycle combustion turbine.

Q. Do you agree with Mr. Baron that CSR customers should be compensated consistent with the avoided cost of a new simple cycle combustion turbine?

[6] Baron Testimony at 27 lines 21-22 and at 28 lines 1-2.

A. Only if CSR customers are providing a similar resource as a simple cycle combustion turbine. However, as previously discussed, Mr. Baron is arguing that the current system reliability event restriction stay in place, which diminishes the value of interrupting CSR customers.

Q. Why are the Companies proposing to leave the CSR credits unchanged from their current levels despite the elimination of the system reliability event restriction?

A. Even with the elimination of the restriction, the Companies' analysis indicates that the CSR credit is appropriate. It is important to note that relying upon a CSR customer to reduce their load when called upon in order to manage system reliability is not the same long-term risk profile as acquiring a supply side resource. For example, a CSR customer can decide to exit the tariff with six months' notice or fail to interrupt when called upon. These risks, combined with the 100 hour limitation on utilization results in a capacity value that is less than the avoided cost of a new simple cycle combustion turbine.

Q. Are the Companies willing to consider maintaining their existing CSR tariffs with the system reliability event restrictions?

A. The Companies are open to solutions that will meet the needs of our customers – those that are interested in the CSR tariff and those that are not. The Companies' proposed changes to the CSR are designed to make it more in line with supply side simple cycle combustion turbine generation. However, some customers, like NAS, might prefer to have curtailments limited to system reliability events. If that is the case, perhaps the existing CSR tariffs could be maintained for such customers but at a reduced credit reflecting the lower value of their ability to interrupt to the system.

Section 3 – OSS Tracker

Q. Both KIUC witness Mr. Kollen and Attorney General witness Mr. Radigan propose that the Commission consider a concept of an OSS Tracker. What is the purpose of an OSS Tracker?

A. Rather than having the OSS margin in the forecasted test period function as a credit against the cost of providing service in base rates, both the KIUC and the AG witnesses propose that customers take the risk and reward as to future OSS margins.[7] If OSS margins turn out to be greater than the forecasted test period, then customers would see a greater reduction in rates. Similarly, if OSS margins turn out to be less than the forecasted test period, then customers' rates will be greater than they otherwise would have been. An OSS Tracker would pass through some percentage of OSS margin to customers each month.

Q. Would an OSS Tracker be better for customers?

A. Not necessarily. An OSS Tracker would certainly put more rate risk onto customers. Under the traditional approach (i.e., no-OSS-Tracker), filed by the Companies, KU and LG&E customers will receive with certainty $0.5 million and $2.7 million, respectively, reduction in revenue requirements for projected OSS margin. With an OSS Tracker, customers will be at risk for the Companies' ability to actually achieve that level of OSS. In fact, if customers get only 80 percent of the margin as proposed by Mr. Radigan, then the Companies would need to achieve 125 percent of the forecasted test year OSS margin just for customers to be indifferent.

Q. What are the risks associated with achieving the forecasted test year OSS margin?

[7] Kollen Testimony at 59-61 and Radigan KU Testimony at 28.

A. The forecasted test year OSS margin is based on the hourly native load energy forecast, generation unit availability adjusted for planned and forced outage risk, forward market price of electricity at the time the 2015 Business Plan was prepared (2nd quarter of 2014), transmission availability assumptions based on historical experience, and forecasted generation unit fuel costs. The PROSYM model simulates the dispatch of the generation fleet to meet native load requirements and makes OSS to the extent a generating unit's production cost is less than the hourly price for electricity – assuming transmission is available.

The Business Plan forecast represents our best view of the expected value for future OSS margin. However, as with any forecast of this type, there is uncertainty associated with all of the variables I described, which means that OSS margins can be greater or less than the expected value.

Q. If the Commission is interested in implementing an OSS Tracker, what guidance would you provide them?

A. I believe there are some basic principles that should guide the Commission in developing an OSS Tracker should it find one desirable:

1. It should be easy to administer. I think all parties in the case agree that OSS margin is a relatively small amount of money when compared to overall revenue requirements, fuel costs, ECR costs, etc. Therefore, the mechanism should not impose large costs on either the Companies or the Commission to administer.

2. It should not alter the Companies' incentives to maximize the value of generation.

3. No reduction for forecasted OSS margin should be made in base rates. Mr. Kollen seems to advocate for adjusting base rates by the forecasted test year amount of OSS margin and then using the OSS Tracker to true-up to actuals, similar to what the FAC does.[8] Adjusting base rates to remove the OSS margin will necessarily increase the revenue requirement in these cases. However, OSS margins vary dramatically from month-to-month such that the OSS Tracker would likely result in a surcharge for customers in many months under Mr. Kollen's approach. Instead, it would be better to make no reduction in base rates for projected OSS margin, i.e., assume an OSS margin of zero for setting base rates, and instead pass through the OSS Tracker the customers' share of whatever margin is achieved each month. This would ensure that customers would never have to pay a surcharge.

Q. Do you believe an OSS Tracker is necessary?

A. No. In general, customers are likely to be risk averse and would prefer the certainty of a rate reduction to betting on future OSS market opportunities. In this particular case, with a future test period, customers will be locking in the expected future value of OSS margin and eliminating the risk associated with unit performance, native load requirements, electricity prices, etc.

Section 4 – Basic Service Charge

Q. Do you agree with CAC witness Mr. Ratchford that increasing the Basic Service Charge will be more harmful to low-income customers than would allocating more of the proposed rate increases to energy charges?[9]

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[8] Kollen Testimony at 59-60.
[9] Ratchford Testimony at 16-17.

A. No. There are many low-income customers who are likely to benefit from the Companies' proposed approach as compared to allocating more of the proposed rate increases to energy charges. Mr. Ratchford's argument seems to be based on assumptions that low-income customers are well positioned to reduce their energy consumption and are also low-usage customers. Unfortunately, neither of these assumptions is likely to be correct for many low-income customers. Mr. Conroy's testimony addresses the issue of low-income energy usage; I address below low-income customers' likely ability to reduce their energy consumption.

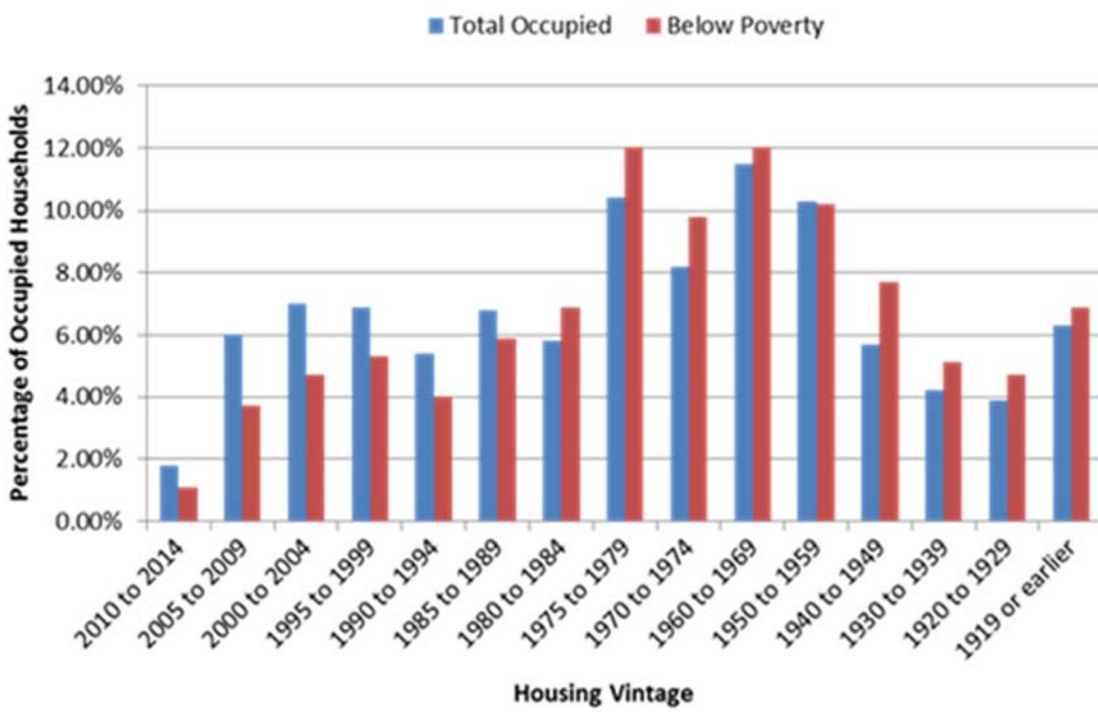
Q. Please explain why low-income customers may not be well positioned to reduce their energy consumption.

A. There are many reasons why low-income customers may find it challenging to significantly reduce their energy consumption. First, Mr. Ratchford stated in response to a data request concerning hypothetical energy-efficiency savings, "[M]any low-income customers and seniors have bare-bones usage now";[10] presumably, customers with "bare-bones usage" are not likely to achieve significant additional energy savings.

[10] Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. Responses to Data Requests Propounded by Kentucky Utilities Company, Response to DR No. 2(d) (Apr. 3, 2015).

Second, low-income customers tend to live in older homes that are often less thermally efficient than newer homes (e.g., have less insulation, lower quality windows, and greater air leakage). As can be seen in Figure 1 below, according to the 2013 American Housing Survey, households living below the poverty level occupy a greater percentage of housing structures built before 1980 than do households living above the poverty level.[11]

Figure 1 – Distribution of Housing Construction Vintage



[11] Data taken from http://www.census.gov/programs-surveys/ahs.html.

Third, Table 2 below shows that households living below the poverty level are much more likely to live in multi-family housing units and manufactured/mobile homes. Manufactured/mobile homes likely present major challenges in materially altering their thermal efficiency while multi-family housing units are likely to be rental properties, thus providing limited financial incentive for low-income households to invest in energy efficiency projects that would attach to the property.

Table 2 – 2013 National Household Survey

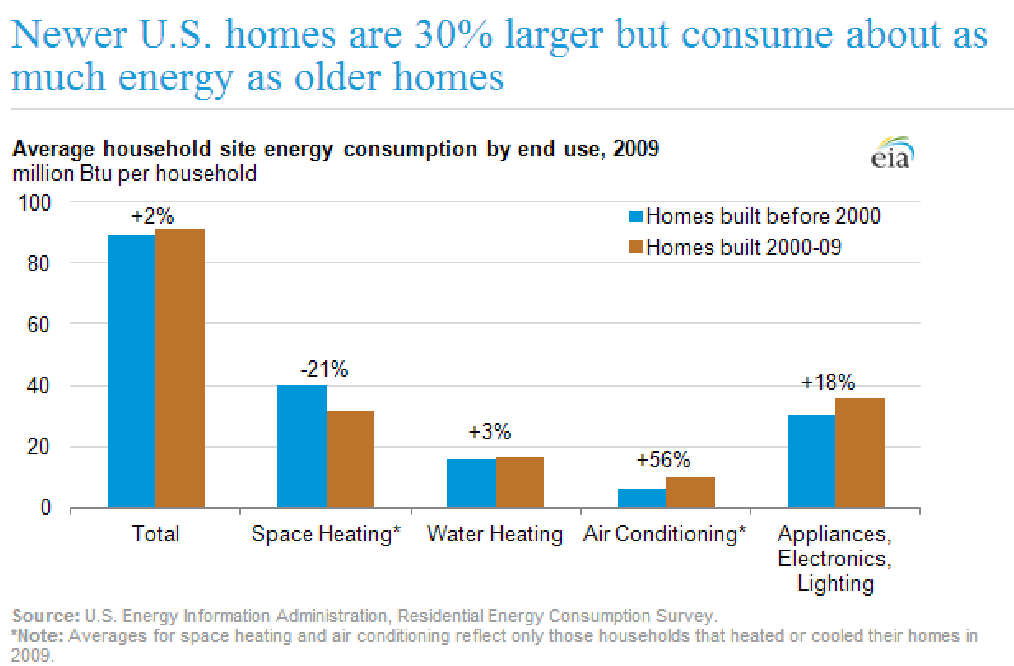
	Total Occupied Units	**Below Poverty Level**
Energy Efficiency Investment		
EE Project Last Two Years[12]	9.4%	6.4%
Home Type		
Single family, detached	64.2%	43.6%
Single Family, attached	5.7%	6.1%
2 to 4 units	7.8%	14.0%
5 to 9 units	4.9%	8.8%
10 to 19 units	4.5%	6.7%
20 to 49 units	3.3%	5.4%
50 or more units	3.7%	6.2%
Manufactured/mobile home or trailer	6.0%	9.2%

[12] Energy efficiency refers to any general home improvement jobs that were done in the last 2 years specifically for energy efficiency purposes and that may or may not have received a federal or state tax credit, or financial incentive from a utility company, for any of the work done to the unit.
< http://www2.census.gov/programs-surveys/ahs/2013/2013%20Definitions.pdf>

Q. While it may be true that low-income people live in older homes, isn't it true that those homes are smaller than newer homes and thus, use much less energy?

A. No. As can be seen in Figure 2 below, although newer homes are indeed 30 percent larger than older homes, older homes actually use about the same amount of energy, with space heating being significantly larger in older homes. This is directly linked to the thermal efficiency issue I just discussed.

Figure 2 – 2009 Residential Energy Consumption Survey



Q. Regardless of the age of their homes, are low-income customers likely to invest in energy efficiency?

A. According to the 2013 American Housing Survey, only 6.4 percent of households living below the poverty level reported making an energy efficiency investment in the prior two years. This was significantly less than the 9.4 percent on all households that reported making an energy efficiency investment. So while some low-income households do indeed invest in energy efficiency, almost 94 percent did not.

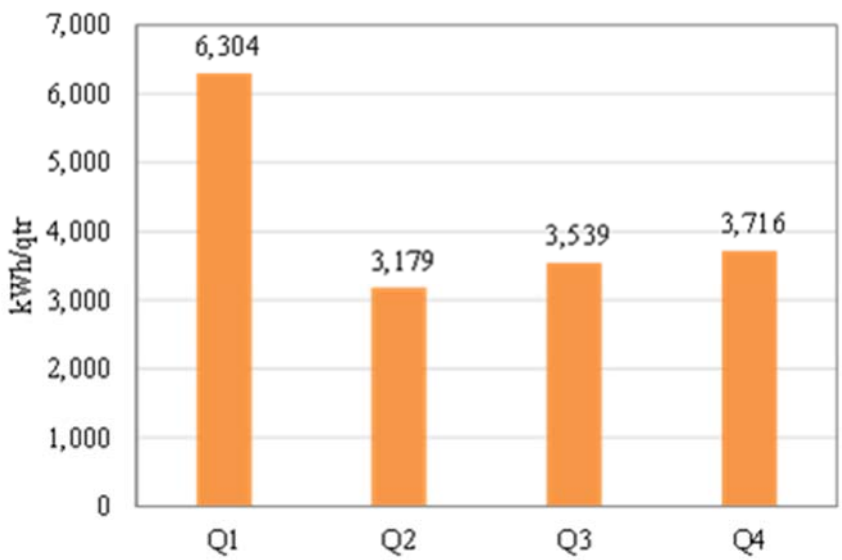
Q. All of the data you have presented is for the U.S. as a whole. How can we know if this is representative of LG&E and KU customers?

A. First, Kentucky ranked 5th (18.8 percent) overall in terms of the percent of individuals below the poverty level from 2009 – 2013,[13] so the state as a whole is among the poorer states. Second, LG&E and KU serve two of the major population centers in Kentucky. Thus, there is no reason to believe that the challenges for investing in energy efficiency among low-income households served by LG&E and KU are materially different from low-income households nationally.

Q. For low-income all-electric customers ("LIAECs"),[14] how important is weather?

A. Using the data that supported the response to SC 1-31, Figure 3 shows average quarterly use per KU LIAEC from 2010 through 2014.

Figure 3 – LIAEC Usage by Quarter (2010-2014 Avg.)



[13] http://www.census.gov/search-results.html?q=kentucky+poverty&search.x=0&search.y=0&search=submit&page=1&stateGeo=none&utf8=%26%2310003%3B&affiliate=census

[14] "Low Income" in this context is defined as a customer that has received third-party bill assistance.

Q. Given the importance of weather on monthly usage, how does a higher Basic Service Charge combined with a lower energy charge impact a LIAEC's monthly bill?

A. Rebuttal Exhibit DSS-1 contains an analysis of variation in KU's LIAEC electricity bills under varying weather conditions and rate structures. The analysis finds that the average LIAEC usage is greater than the 14,400 kWh average KU residential usage that was the basis of the filed rate design. The analysis in Rebuttal Exhibit DSS-1 shows that for higher usage customers like KU's LIAECs, a tariff design as proposed by KU that properly reflects cost allocation between the Basic Service Charge and the energy charge is advantageous compared to one that shifts costs from the Basic Service Charge to a higher energy charge. Figure 4 in Rebuttal Exhibit DSS-1 shows the annual bill for KU LIAECs with the rate design filed by the Company as compared to an alternative rate design that holds the Basic Service Charge at current levels and artificially increases the energy rate. With the rate design filed by KU, the average LIAEC saves around $15 per year assuming normal weather.

Q. Is it fair to say that by increasing the Basic Service Charge instead of the energy rate that the Companies are reducing LIAECs' financial exposure to extreme weather events like those experienced in January 2014 and 2015?

A. While that was not the primary goal of the rate design, it certainly is a positive attribute for high usage-LIAECs. As can be seen on page 7-8 of Rebuttal Exhibit DSS-1, KU simulated the impact of hotter and milder summers and colder and milder winters on the usage of its LIAECs. The results (see Rebuttal Exhibit DSS-1, Figure 6) show that the lower energy charge proposed by KU decreases the average LIAEC's annual bill by between $20 and $26 in a high usage year.

Q. Do you agree with Sierra Club witness Mr. Chernick that increasing the Basic Service Charge as opposed to increasing the energy rate will materially reduce customers' incentives to manage their electricity usage and could cause sales to increase?

A. No. I previously provided extensive testimony to the Commission regarding the price responsiveness of customers in Case No. 2012-00428.[15] As I stated in that testimony, numerous studies have shown over the years that price is not the primary driver of the demand for electricity and that it is very price "inelastic," meaning that it takes a large percentage change in price to produce a very small change in the quantity demanded. It is hard to imagine that most customers would differentiate between the Companies' filed residential energy rates (7.618 cents/kWh for LG&E and 8.057 cents/kWh for KU) and the alternative rates (8.355 cents/kWh for LG&E and 8.661 cents/kWh for KU) that would result from keeping the Basic Service Charge at current levels. It is hard to believe that customers would make materially different decisions regarding conservation and/or energy efficiency technology investment based on such small differences in the price per kWh.

Q. Are you providing supporting documentation of your analysis?

A. Yes. Support for this analysis is provided in Appendix A to my testimony. Because of the spreadsheet's large file size, it is being produced on compact disc.

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[15] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Testimony of David S. Sinclair at 4-5 (January 28, 2013).

Q. Did you test Mr. Chernick's assertion that this simple rate design, if not undone, would cause sales to increase by 2.5 percent for KU and 2 percent for LG&E?

A. Yes. We decreased electricity prices by 9 percent in KU's SAE model for residential customers, which resulted in a 0.9 percent increase in sales. This result was well below the 2.5 percent increase included in Mr. Chernick's testimony. For LG&E, a price reduction of 7 percent increased sales by less than 0.4 percent. This result was well below the 2 percent increase referenced by Mr. Chernick.

Q. Is Mr. Ratchford's assertion that KU's proposal to increase its residential Basic Service Charge will reduce incentives for energy efficiency correct?[16]

A. No. A customer who is interested in saving money and deciding whether to make an energy-efficiency investment to create such savings will consider whether the measure will produce savings greater or lesser than the measure's cost. Under KU's current Rate RS, a customer saving 100 kWh per month will save $7.74 per month in Rate RS energy charges. Under KU's proposed Rate RS, the same customer will save $8.06 per month using the same energy-efficiency measure. The savings are indisputably greater, and the energy-efficiency incentive is indisputably greater.

Q. Does this conclude your testimony?

A. Yes, it does.

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[16] Community Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. Responses to Data Requests Propounded by Kentucky Utilities Company, Response to DR No. 2(b) (Apr. 3, 2015).

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis 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.

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of April 2015.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

2015 KU Rate Assessment for All-Electric KU Customers Receiving Third Party Assistance

PPL companies

Sales Analysis and Forecasting

April 2015

Table of Contents

List of Terms

CDD	Cooling Degree Days
CTN	Colder Than Normal
The Companies	Louisville Gas and Electric Company and Kentucky Utilities Company
HDD	Heating Degree Days
KU	Kentucky Utilities Company
LG&E	Louisville Gas and Electric Company
LIAEC	Low Income All-Electric Customer
Low Income	Defined as Customer that has received third-party bill assistance
SAF	Sales Analysis and Forecasting
SD	Standard Deviation
UPC	Use per Customer
WTN	Warmer Than Normal

1 Executive Summary

Louisville Gas and Electric ("LG&E") and Kentucky Utilities' ("KU") (collectively "the Companies") Sales Analysis and Forecasting ("SAF") group conducted an analysis of all-electric customers on the residential rate in the KU service territory who received third party assistance for their utility bills over the past five years. The goal was to determine the impact on the average annual electricity bill for these customers under the proposed rate tariff in Case No. 2014-00371 which has an increased basic service charge ($18/month) versus a theoretical tariff with an unchanged basic service charge ($10.75/month) and a higher energy charge.

Rate Calculation

- SAF used the proposed basic service charge and energy charge from Case No. 2014-00371 to calculate the expected revenue recovered from an average usage customer on the KU residential rate (14,400 kWh) in a one year period.
- This proposed rate was compared to a hypothetical rate that leaves the basic service charge unchanged from current levels but with a higher energy charge so that the annual bill for the average customer on the KU residential rate would be unchanged.

Customer Identification

- SAF looked at usage from KU all-electric customers that received third party assistance for their bills (LIAEC – Low Income All-Electric Customers) from Jan 1, 2010 through Jan 9, 2015.
- Historical usage and customer counts were pulled by billing period to determine the historical use per customer ("UPC").

Normalizing Usage

- Using historical UPC data, SAF ran a regression to forecast quarterly UPC values for KU LIAEC, assuming normal weather.
- Normal temperatures were obtained using the 20-year average (1994-2004 ex. 2000) degree day counts and standard deviations for each quarter.

Scenario Analysis

- Normal Temperature Scenario: Using normal temperatures, we forecasted an average annual UPC for KU LIAEC of 16,832 kWh.
- Weather Scenarios: Using the same methodology as in the Normal Temperature Scenario, additional scenarios were run using varying weather conditions.
  - Impact on annual bill of above-/below-normal temperatures in Q1
  - Impact on annual bill of high (cold Q1/Q4, hot Q3) and low (warm Q1/Q4, mild Q3) scenarios for customer energy usage for an entire year

Conclusions

- Because the average usage for KU LIAEC higher than the 14,400 kWh used in the overall residential rate design, the filed rate design with a higher basic service charge and a lower energy charge will lead to slightly smaller bills for KU LIAEC.

- Temperature conditions that cause annual UPC to increase will be less burdensome to KU LIAEC with the Company's filed rate design.

- Because weather conditions explain the large majority of quarterly UPC for KU LIAEC, it is unlikely that a rate design alternative with a higher energy charge would lead to any material decrease in usage for this customer group.

2 Methodology

The Company does not collect information on customer income. However, the Company does know that 91,663 KU customers received financial assistance on their electric bills at least once and/or participated in the WeCare program during the period January 1, 2010 through January 9, 2015. From this group of customers that received some form of financial assistance with their bill, SAF analyzed the consumption for the all-electric customers. SAF focused on all-electric customers because their usage is likely larger than dual-fuel customers and thus would have the most potential to benefit from efforts to reduce electricity consumption. The usage of these customers was aggregated on a quarterly basis to determine the average UPC by quarter for KU all-electric customers who receive third party assistance ("LIAEC").

Using this historical data, SAF ran a regression to normalize UPC values for a full year assuming normal temperatures. The model output is shown in Figure 1.

Figure 1 – Quarterly KU LIAEC Usage Regression Results

The SAS System 11:20 Tuesday, April 7, 2015 3

The AUTOREG Procedure

Dependent Variable KULI_AE

Ordinary Least Squares Estimates

SSE	0.5794051	DFE	15
MSE	0.03863	Root MSE	0.19654
SBC	0.90648956	AIC	-4.0721718
MAE	0.11683388	AICC	0.21354248
MAPE	2.80639898	Regress R-Square	0.9826
Durbin-Watson	1.6302	Total R-Square	0.9826

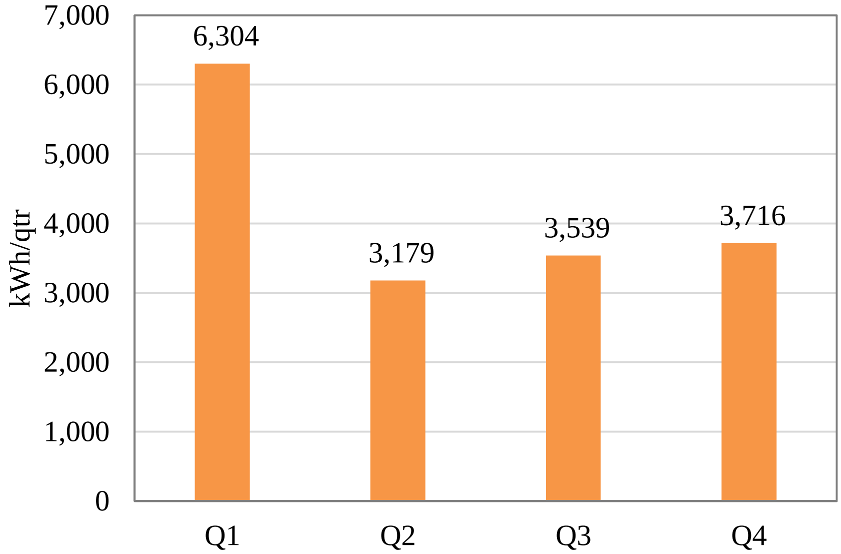
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	1.9690	0.3970	4.96	0.0002
HDDQ1	1	0.001761	0.000162	10.85	<.0001
HDDQ2	1	0.003659	0.001222	2.99	0.0091
CDDQ3	1	0.001796	0.000458	3.92	0.0014
HDDQ4	1	0.001012	0.000234	4.32	0.0006

The time period for the regression is Q1 2010 (Jan-Mar) through Q4 2014 (Oct-Dec) for a total of 20 observations. The explanatory variables are as follow:

HDDQ1 = Lexington (Bluegrass Airport) total heating degree days ("HDD") during first quarters
HDDQ2 = Lexington (Bluegrass Airport) total HDD during second quarters
CDDQ3 = Lexington (Bluegrass Airport) total cooling degree days ("CDD") during third quarters
HDDQ4 = Lexington (Bluegrass Airport) total HDD during fourth quarters

The R-squared value for this equation is 0.9826, meaning that 98.26% of the quarterly UPC is explained by temperature fluctuations. As a result, we can conclude that the usage of customers in this group has been extremely sensitive to weather over the past five years. Figure 2 shows the considerable deviations in usage by quarter.

Figure 2 – KU LIAEC Usage by Quarter (2010-2014 Average)



3 Average Annual Bill Analysis

Using the regression results in Section 2, SAF forecasted UPC values for each quarter in 2015 under a "normal" temperature scenario. Normal in this case refers to the 20-year average heating and cooling degree days at Bluegrass Airport from 1994-2014.[1] The UPC was forecasted to be 16,832 kWh/year for a KU all-electric customer on third party bill assistance assuming normal weather.

The proposed KU residential electricity tariff was developed based on an average customer usage of 1,200 kWh/month, or 14,400 kWh/year. Based on this, SAF constructed a rate comparison calculator to compare the annual revenue recovered from a KU customer in a year under the proposed rate structure ($18/month basic service charge) and one in which in the energy charge was raised to account for keeping the basic service charge unchanged ($10.75/month). Figure 3 shows the annual revenue that would be recovered under each rate structure from a customer who uses 14,400 kWh/year of electricity would be the same.

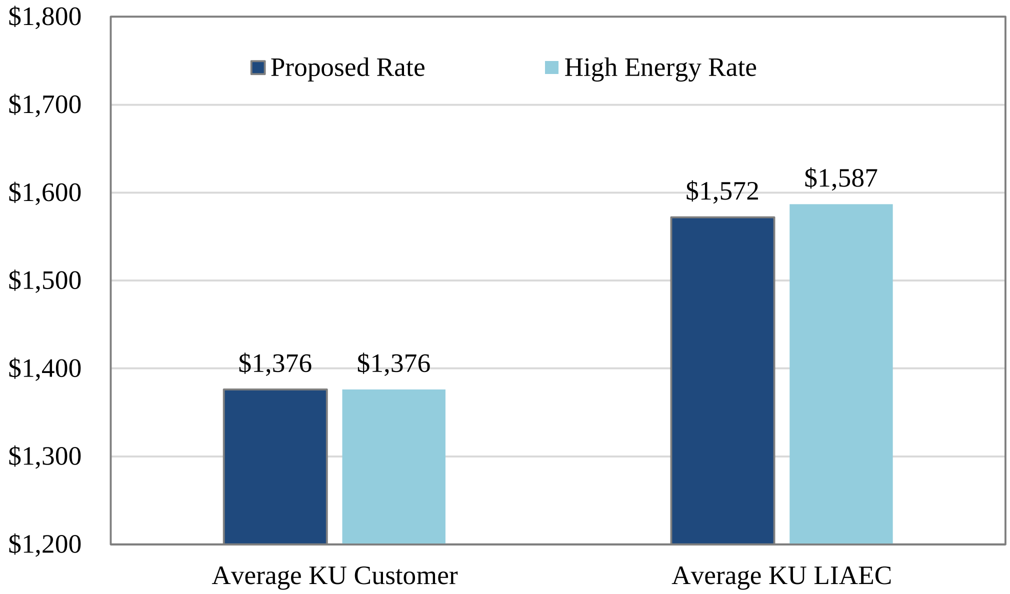
Figure 3 – Two Competing Rate Structures

Annual Bill	Proposed	High Energy Charge
Basic Service Charge	$18.00	$10.75
Energy Charge ($/kWh)	$0.0806	$0.0866
Annual Revenue	$1,376.21	$1,376.21

Because the average KU LIAEC is forecasted to use 16,832 kWh/year per our analysis in Section Two, the bill impact of the different rate designs will not be the same. Figure 4 shows the average annual bill for a customer using this amount of electricity under both the proposed and high energy rate structures. Regardless of rate design, the bill is materially higher for the KU LIAEC because their energy consumption is well above the 14,400 kWh/year annual average for residential customers in general. Additionally, the annual bill is higher under the high energy rate structure than under the proposed tariff. In fact, any time that average annual usage rises above the consumption level that was used to construct the rate, the annual bill will be higher under the high energy charge rate as compared to the proposed rate with the higher basic service charge.

[1] Data for the year 2000 was incomplete and/or bad and so was excluded from the average.

Figure 4 – Average Annual Bill Assuming Normal Temperatures

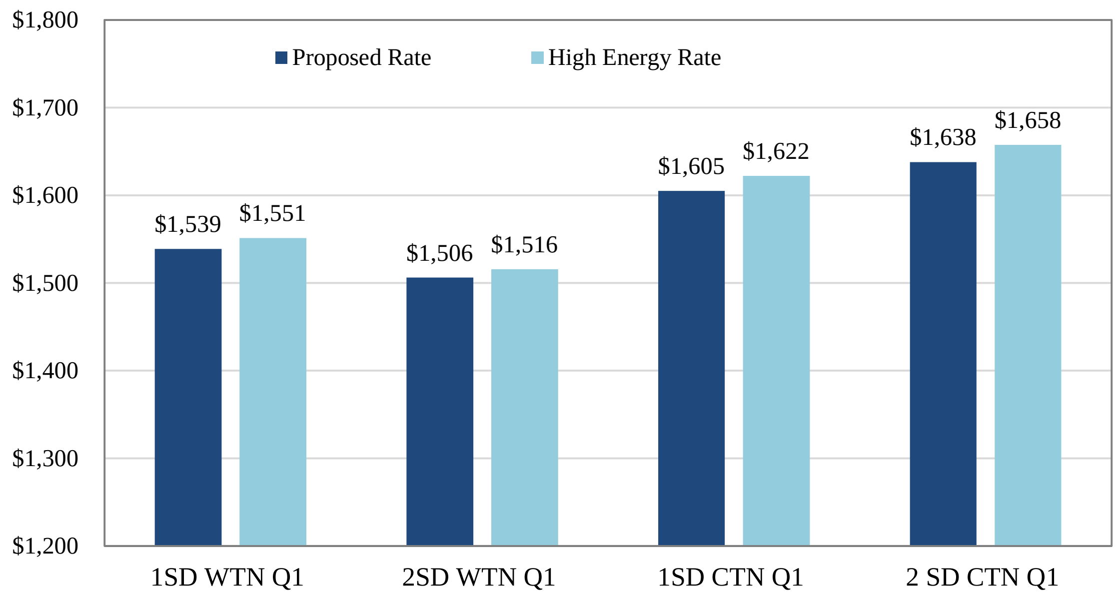


4 Scenario Analysis

SAF also ran scenario analyses to discern the impact of different temperature conditions on KU LIAEC bills. The first scenario looks at the impact of colder- or warmer-than-normal temperature conditions during the first quarter, the period when UPC is highest for KU LIAEC.

Figure 5 shows the variation in the average KU LIAEC bill from temperature movements of one and two standard deviations from normal (assuming a normal distribution). This data demonstrates that even during extremely mild first quarters (the 2SD WTN scenario is only a 2.5 percent probability assuming a normal distribution), average annual energy bills are higher for KU LIAEC. And during colder-than-normal years, as were seen in 2014 and 2015, energy bills are much more burdensome to KU LIAEC than for other KU customers.

Figure 5 –Average Annual Bill for KU LIAEC Assuming Extreme First Quarter Temperature Deviations

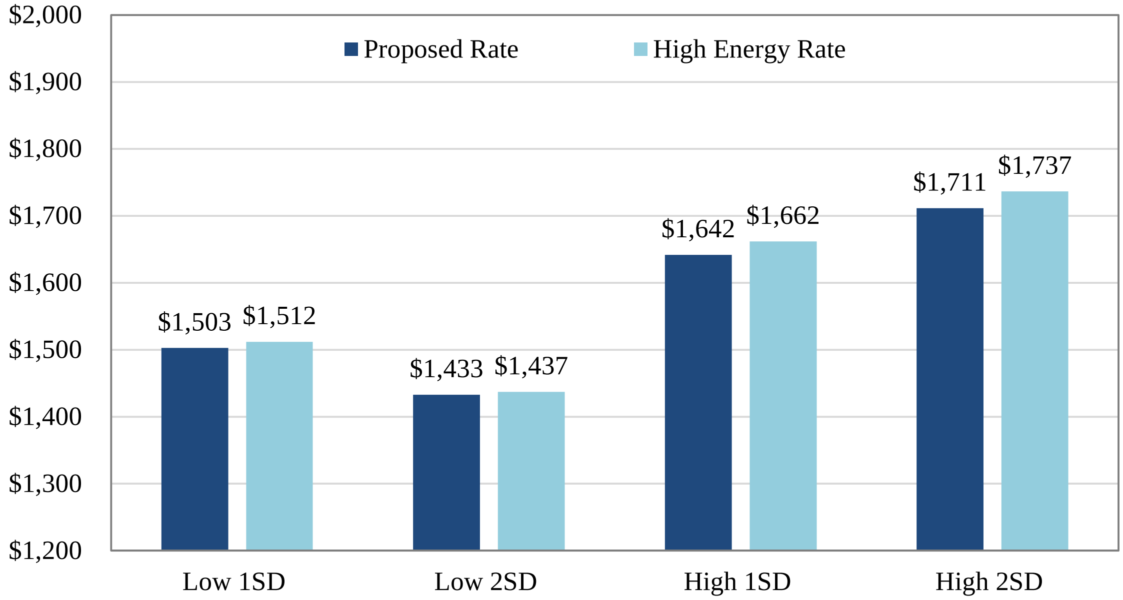


1SD WTN Q1: one standard deviation warmer-than-normal temperatures in the first quarter
2SD WTN Q1: two standard deviation warmer-than-normal temperatures in the first quarter
1SD CTN Q1: one standard deviation colder-than-normal temperatures in the first quarter
2SD CTN Q1: two standard deviation colder-than-normal temperatures in the first quarter

SAF also considered another scenario where temperature conditions are extremely severe in each direction. The high usage scenario involves one- and two-standard deviation moves in temperatures that send electricity consumption higher in each quarter (CTN Q1 and Q4, WTN Q3, neutral Q2 since there is both heating and cooling load in these months), and vice versa for the low usage scenario.

Figure 6 shows that, even under the extremely unlikely (<1%) scenario where temperatures push usage dramatically lower (low 2SD), KU LIAEC still see average annual bills slightly higher under the high energy charge rate as compared to the proposed rate. This "stacking the deck" type analysis shows that it is nearly impossible for an average usage KU LIAEC to benefit from a high energy charge tariff as opposed to the proposed rate.

Figure 6 – Average Annual Bill for KU LIAEC Assuming Extreme Temperature Deviations During The Year



Low 1SD: 1 SD WTN Q1&Q4, 1 SD CTN Q3, neutral Q2
Low 2SD: 2 SD WTN Q1&Q4, 2 SD CTN Q3, neutral Q2
High 1SD: 1 SD CTN Q1&Q4, 1 SD WTN Q3, neutral Q2
High2SD: 2 SD CTN Q1&Q4, 2 SD WTN Q3, neutral Q2

5 Conclusion

Because the average KU LIAEC usage is higher than the 14,400 kWh used in the overall residential rate design, the filed rate design with a higher basic service charge and a lower energy charge will lead to slightly smaller bills for KU LIAEC.

Additionally, temperature conditions that cause annual UPC to increase will be less burdensome to KU LIAEC with the Company's filed rate design. Finally, because weather conditions explain the large majority of quarterly UPC for KU LIAEC, it is unlikely that a rate design alternative with a higher energy charge would lead to any material decrease in usage for this customer group.

Attachment in Excel

The attachment(s) provided in separate file(s) in Excel format.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2014-00371**

In Re the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

REBUTTAL TESTIMONY OF
ROBERT M. CONROY
DIRECTOR, RATES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Dated: April 14, 2015

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

A. My name is Robert M. Conroy. I am Director of Rates 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 respond to certain of the arguments presented in the testimony of Stephen J. Baron on behalf of Kentucky Industrial Utility Customers, Inc. ("KIUC"), Steve W. Chriss on behalf of Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"), Ronald L. Willhite on behalf of Kentucky School Boards Association ("KSBA"), Malcolm J. Ratchford on behalf of Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. ("CAC"), Marlon Cummings on behalf of Association of Community Ministries, Inc. ("ACM"), Paul Chernick on behalf of Sierra Club, and Patricia D. Kravtin on behalf of Kentucky Cable Telecommunications Association ("KCTA").

Specifically, I address (1) certain of Mr. Chernick's, Mr. Ratchford's, and Mr. Cummings's arguments concerning the Companies' proposed residential Basic Service Charge; (2) arguments of Mr. Baron, Mr. Chriss, and Mr. Willhite concerning the Companies' revenue allocations; (3) certain arguments of Mr. Chernick concerning the Companies' proposed Residential Time-of-Day ("RTOD") rates; (4) arguments of Mr. Baron concerning LG&E's proposal to merge its Commercial Time-of-Day Primary ("CTODP") and Industrial Time-of-Day Primary ("ITODP") rates; (5) arguments of Mr.

Chriss concerning the Companies' tariffed definition of "industrial" for demand-side management ("DSM") purposes; (6) certain arguments of Mr. Willhite concerning Rate AES (All-Electric Schools) and his proposal for a sports-field-lighting rate; and (7) certain arguments of Ms. Kravtin concerning the Companies' current Rate CTAC (Cable Television Attachment Charges).

The Companies' Proposed Residential Basic Service Charges Are Based on the Companies' Cost of Service, Will Not Materially Affect Current Incentives for Energy Efficiency or Distributed Generation, and Will Not Materially Affect Customers' Ability to Reduce their Bills

Q. Will the Companies' proposed residential rates, including the Companies' proposed Basic Service Charge, provide customers materially identical incentives to engage in energy efficiency and to install distributed generation as customers have today?

A. Yes. KU's proposed Rate RS energy charge is $0.08057 per kWh, which is slightly higher than its current Rate RS energy charge of $0.07744 per kWh, and will provide a materially identical incentive for KU customers to engage in energy efficiency and to install distributed generation. For example, if a KU customer with average usage (about 1,200 kWh per month) were evaluating an energy-efficiency measure to reduce usage by 10%—a significant usage reduction—the measure would produce energy-charge savings of $9.29 per month under KU's current rates and savings of $9.67 under KU's proposed rates. It seems unlikely that a difference of less than $0.40 per month would materially affect a customer's energy-efficiency decisions.

Similarly, LG&E's proposed Rate RS energy charge is $0.07618 per kWh, which is slightly lower than its current Rate RS energy charge of $0.08076 per kWh, and will provide a materially identical incentive for LG&E customers to engage in energy efficiency and to install distributed generation. For example, if an LG&E customer with average usage (about 1,000 kWh per month) were evaluating an energy-efficiency measure to reduce usage by 10%—a significant usage reduction—the measure would produce energy-charge savings of $8.07 per month under LG&E's current rates and savings of $7.62 under LG&E's proposed rates. It seems unlikely that a difference of $0.45 per month would materially affect a customer's energy-efficiency decisions.

Because there is little reason to believe that the Companies' proposed residential Basic Service Charges and their related residential energy charges will have much, if any, effect on customers' decisions to pursue energy-efficiency measures, the Companies' proposed residential rates comport with the Commission order Mr. Chernick cites that states, "[W]e will strive to avoid taking actions that might disincent energy efficiency."[1] But the Companies' proposed Basic Service Charges comport also with the Commission's long history of approving cost-based rates; indeed, the Commission has described cost-based ratemaking as "the foundation of the Commission's rate-making philosophy."[2]

Q. Does this same analysis apply to Mr. Cummings's and Mr. Ratchford's concerns about low-income customers' ability to reduce their bills through energy efficiency?

A. Yes. As I noted above, under KU's current Rate RS, a 10% reduction in an average residential customer's usage will produce average monthly energy-charge savings of $9.29, and under proposed rates the savings will be $9.67. Therefore, Mr. Ratchford's assertion that KU's proposed residential Basic Service Charge will result in "far less incentive for

[1] Chernick KU Testimony at 4, *quoting In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2012-00221, Order at 11 (Dec. 20, 2012); Chernick LG&E Testimony at 4, *quoting In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity, Approval of Ownership of Gas Service Lines and Risers, and a Gas Line Surcharge*, Case No. 2012-00222, Order at 15 (Dec. 20, 2012).

[2] *In the Matter of: Big Rivers Electric Corporation's Notice of Changes in Its Rates for Electricity Sold to Member Cooperatives*, Case No. 9163, Order at 26-27 (May 6, 1985) ("The appeal of this rate structure is that rates are still based on cost, which is the foundation of the Commission's ratemaking philosophy.").

customers to conserve energy" is incorrect; under KU's proposed Rate RS, customers will have a greater incentive to save money through conservation and energy efficiency.[3]

Similarly for LG&E, a 10% reduction in an average residential customer's usage under current rates will produce average monthly energy-charge savings of $8.07, and under proposed rates the savings will be $7.62. Therefore, Mr. Cummings's assertion that LG&E's proposed residential Basic Service Charge will cause low-income customers to "lose the ability to save money by conserving energy" is incorrect; under LG&E's proposed Rate RS, customers will retain an almost identical ability to save money through conservation and energy efficiency.[4]

Q. Will some low- or fixed-income customers benefit from having a Basic Service Charge that more accurately reflects the Companies' cost of service?

A. Yes. When compared to the residential class as a whole, a significant number of the Companies' low-income customers (as defined by residential customers who received assistance from a third-party agency) have above-average energy usage,[5] and the average usage of each Company's low-income customers is higher than the average of each Company's residential class taken as a whole.[6] To the extent the Companies recover fixed customer-specific and distribution-system costs through volumetric energy rates, customers with above-average energy consumption—including low-income customers—will pay more fixed cost than they should for their service. Periods with above-average numbers of extreme weather events, which tend to increase customers' usage, exacerbate

[3] Ratchford Testimony at 17.
[4] Corrected Cummings Testimony at 8.
[5] *See* Companies' Response to KU Sierra Club 2-4; Companies' Response to LG&E Sierra Club 2-4. These responses show that a majority of KU's low-income customers have above-average usage (14,545 of a total 28,031 low-income customers), and that a significant minority of LG&E's low-income customers have above-average usage (8,368 of a total 20,437 low-income customers).
[6] *See* Companies' Response to KU Sierra Club 1-31(b); Companies' Response to LG&E Sierra Club 1-31(b).

this problem. Therefore, a residential Basic Service Charge that more accurately reflects the Companies' fixed customer-specific and distribution-system costs will actually help low-income customers with usage above the residential class average, and will help reduce bill volatility for all customers during periods of extreme weather events; it will not "penalize low-income seniors and other low-income customers," as Mr. Ratchford claims.[7]

Q. Do you agree with Mr. Chernick's assertion that "rates should be designed to provide price signals for customer behavior"?[8]

A. No. The Commission has clearly stated that cost-based ratemaking—not just revenue allocation as Mr. Chernick would have it,[9] but ratemaking—is "the foundation of the Commission's rate-making philosophy."[10] The Commission has also stated that cost-based rates and economical energy-efficiency are not at odds; rather, they complement each other: "[T]he Commission is very much interested in cost-of-service-based rates and demand-side management programs that incentivize both the utility and customers to practice energy efficiency in a cost-effective manner."[11] Therefore, to the best of the Companies' knowledge the Commission has not ordered or even requested that a utility depart from cost-of-service-based rates to create incentives for energy efficiency, but rather has encouraged the aggressive development of economical energy-efficiency programs consistent with cost-of-service-based rates.

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[7] Ratchford Testimony at 17.
[8] Chernick Testimony at 13.
[9] *See* Chernick KU Testimony at 13 lines 2-4 ("The primary objective of a cost of service study is to equitably divide up a fixed set of revenue requirements among customer classes based on broad considerations of cost drivers."); Chernick LG&E Testimony at 13 lines 5-7 ("The primary objective of a cost of service study is to equitably divide up a fixed set of revenue requirements among customer classes based on broad considerations of cost drivers.").
[10] *In the Matter of: Big Rivers Electric Corporation's Notice of Changes in Its Rates for Electricity Sold to Member Cooperatives*, Case No. 9163, Order at 26-27 (May 6, 1985) ("The appeal of this rate structure is that rates are still based on cost, which is the foundation of the Commission's ratemaking philosophy.").
[11] *In the Matter of: General Adjustment of Electric Rates of East Kentucky Power Cooperative, Inc.*, Case No. 2008-00409, Order at 6 (Mar. 31, 2009).

Against this clear and longstanding Commission precedent requiring cost-of-service-based ratemaking, Mr. Chernick states he is aware of only one quote from two Commission orders—both of which are from the Companies' 2012 base-rate cases—to support his claim that rates should be designed to shape customers' behavior;[12] in fact, the quoted text provides no such support. The first portion of Mr. Chernick's chosen quote states:

> For over 30 years, the Commission has historically noted the importance of energy efficiency (conservation) as a ratemaking standard. "It is intended to minimize the 'wasteful' consumption of electricity and to prevent consumption of scarce resources …."[13]

The order the Commission quoted in the quote above was the Commission's February 28, 1982 order in Administrative Case No. 203.[14] The Commission's quote above contains an important ellipsis; the full relevant quote from the Administrative Case No. 203 order states:

> CONSERVATION
>
> This purpose focuses on the final consumers of electric power. It is intended to minimize the "wasteful" consumption of electricity and to prevent consumption of scarce resources which would be more valuable in some alternative productive use. <u>Prices which reflect the cost of the resources necessary to produce an additional unit of electricity will encourage conservation</u>.[15]

The 1982 order goes on to state:

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[12] *See* Responses to KU Data Requests on Behalf of Sierra Club, Response to DR No. 1; Responses to LG&E Data Requests on Behalf of Sierra Club, Response to DR No. 1.

[13] Chernick KU Testimony at 4, *quoting In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2012-00221, Order at 7 (Dec. 20, 2012); Chernick LG&E Testimony at 4, *quoting In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity, Approval of Ownership of Gas Service Lines and Risers, and a Gas Line Surcharge*, Case No. 2012-00222, Order at 11 (Dec. 20, 2012).

[14] *In the Matter of: The Determinations with Respect to the Ratemaking Standards Identified in Section 111(d)(1)-(6) of the Public Utility Regulatory Policies Act of 1978*, Administrative Case No. 203, Order (Feb. 28, 1982).

[15] *Id.* at 7 (emphasis added).

> [T]he preponderance of opinion from companies, intervenors, staff, and the public was that cost of service studies provide a logical starting point for designing rates. The Commission has determined that it is appropriate to implement the cost of service standard. There must be some basis for rates, and the Commission believes that costs have a stronger claim to this role than does any other basis.[16]

The 1982 order even goes on to state that declining-block rates, though generally prohibited, would be permissible if a utility could demonstrate that its costs justified a declining-block demand or energy charge.[17] The Companies are not proposing declining-block rates, of course; but it is important to see that the Companies' proposed residential Basic Service Charge is consistent with this longstanding precedent the Commission recently cited.

The Companies' proposed residential Basic Service Charge is also consistent with another order the Commission cited in its final orders in the Companies' 2012 rate cases, namely the Commission's final order in Case No. 2011-00037.[18] In that order, the Commission approved a stepped increase in Owen Electric Cooperative Corporation's monthly residential customer charge from $11.30 (already higher than the Companies' residential Basic Service Charge) to $20.00.[19] Owen's $20.00 residential customer—which is more than 10% higher the Companies' proposed residential Basic Service Charge—went into effect on March 1, 2015.[20]

The Companies' proposed residential Basic Service Charges are also consistent with the portion of the Commission's final orders in the Companies' 2012 rate cases that

[16] *Id.* at 18.
[17] *Id.* at 23-24.
[18] *In the Matter of: Application of Owen Electric Cooperative Corporation for an Order Authorizing a Change in Rate Design for Its Residential and Small Commercial Rate Classes, and the Proffering of Several Optional Rate Designs for the Residential Rate Classes*, Case No. 2011-00037, Order (Feb. 29, 2012).
[19] *Id.* at 9.
[20] Owen Electric Cooperative, Inc. P.S.C. Ky. No. 6, 14th Revised Sheet No. 1.

Mr. Chernick quotes concerning the Commission's desire not to provide disincentives to energy efficiency in view of potentially significant cost and regulatory issues that might arise in the near future: ""[W]e will strive to avoid taking actions that might disincent energy efficiency."[21] As I described above, the proposed Basic Service Charges do not materially affect the incentives the Companies' residential customers currently have to engage in energy efficiency, and therefore accord fully with the Commission's statement in the Companies' 2012 base-rate cases while also according with the Commission's longstanding axiom that a utility's base rates should reflect its cost of service.

Finally, it is the Companies' long-held view that their role is to minimize operating costs subject to all applicable legal requirements—including their obligation to serve all customers seeking service in their service territories—while providing safe and reliable service and excellent customer service. The Companies then seek to reflect accurately their current cost of providing such service through rates that are fixed to the extent the Companies' costs are fixed and variable to the extent the Companies' costs vary. The Companies do not seek to give customers an incentive to purchase more energy than the Companies' accurately reflected current costs would cause them to demand; for example, the Companies long ago removed declining-block rate schedules from their tariffs. But neither do the Companies seek to give customers an incentive to purchase less energy than the Companies' accurately reflected current costs would cause them to demand; rather, the Companies believe their role is safely and reliably to provide all the energy their customers

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[21] Chernick KU Testimony at 4, *quoting In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2012-00221, Order at 11 (Dec. 20, 2012); Chernick LG&E Testimony at 4, *quoting In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity, Approval of Ownership of Gas Service Lines and Risers, and a Gas Line Surcharge*, Case No. 2012-00222, Order at 15 (Dec. 20, 2012).

demand under rates that accurately reflect the Companies' current cost of service. This philosophy comports with long standing cost-of-service principles followed over many years by the Commission, the Companies, and the utility industry. Therefore, because the Companies' proposed residential Basic Service Charges are cost-of-service-based, do not materially affect energy-efficiency or distributed-generation incentives, and are consistent with established and recent Commission precedents, I recommend the Commission approve the Companies' proposed residential Basic Service Charges.

Revenue Allocation Should Reflect Cost of Service Tempered by Gradualism

Q. Both Mr. Baron and Mr. Chriss support the Companies' proposed revenue allocations.[22] But they have different proposed revenue allocations if the Commission approves revenue increases less than the Companies have requested.[23] Which of their proposals, if any, do the Companies support?

A. KIUC witness Mr. Baron suggests that the Companies' revenue allocations should not change if the Commission approves revenue increases for the Companies that are less than what the Companies have requested.[24] Wal-Mart witness Mr. Chriss, on the other hand, proposes that the Commission use a revenue allocation that would move the various rate classes' rates of return closer to the system average if the Commission does not approve the Companies' full revenue-increase requests.[25] Because the Companies support cost-of-service based rates and revenue allocations, they would support Mr. Chriss's proposed revenue allocation methodology, applied judiciously and consistently with gradualism, if the Commission does not approve the Companies' full revenue-increase requests.

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[22] Baron Testimony at 20; Chriss KU Testimony at 17-18; Chriss LG&E Testimony at 15.
[23] Baron Testimony at 22; Chriss KU Testimony at 17-18; Chriss LG&E Testimony at 15.
[24] Baron Testimony at 22.
[25] Chriss KU Testimony at 17-18; Chriss LG&E Testimony at 15.

Q. How do the Companies' proposed revenue allocations comport with gradualism?

A. The Companies seek in each base-rate case to move their revenue allocations and rates closer to their cost of service, but have made the necessary changes incrementally to comport with the ratemaking doctrine of gradualism and to avoid rate shocks. Because the proposed revenue increase and resulting rate increases are significant for KU in particular, the Companies' view was that equal-percentage revenue increases for all rate classes best served the doctrine of gradualism without harming the Companies' efforts to move closer to truly cost-of-service-based revenue allocations. KSBA witness Mr. Willhite has objected to the Companies' revenue allocations, arguing effectively that the Companies should ignore gradualism and allocate as much of the proposed revenue increases as necessary to rate classes with rates of return lower than the system average before making equal percentage increases to all rate classes with any revenue remaining to be allocated.[26] The Companies respectfully disagree; gradualism, which the Companies have followed when proposing rates in prior rate case proceedings, is an important tenet of ratemaking, particularly when relatively large increases are necessary to ensure the Companies can continue to provide safe and reliable service at the lowest reasonable cost. But as I testified above, the Companies do agree with Wal-Mart witness Mr. Chriss's proposal for moving toward cost-of-service-based revenue allocations if the Commission approves lower revenue increases than those the Companies requested.

<u>Both of the Companies' Proposed Optional Residential Time-of-Day Rates Are Reasonable</u>

Q. Are there any matters you would like to address concerning the Companies' proposed optional residential time-of-day rates, Rates RTOD-D and RTOD-E?

[26] Willhite KU Testimony at 9-10; Willhite LG&E Testimony at 9-10.

A. Yes. Although Dr. Blake's testimony addresses the particular criticisms Mr. Chernick has made concerning the Companies' proposed optional Rates RTOD-D and RTOD-E, there are several observations I would like to make. First, the rates are indeed optional; if customers do not find them appealing, they need not take service under them. Second, though the rates are not pilot rates or programs, the Companies do plan to learn from customers' experiences with them—including whether customers choose them and decide to continue taking service under them—and will propose changes that will improve the rates, if any improvements are evident, in subsequent base-rate cases. Third, because the rates are entirely optional and subject to improvement in later base-rate cases, it is premature at best for Mr. Chernick to advocate against offering Rate RTOD-D; presumably the worst that can happen is no customers seek to take service under the rate and the Companies revise it in subsequent base-rate cases.

The Companies have had numerous pilot programs on time-of-day rates over the years and have extensive experience with time-of-day rates for large customers; the Companies therefore have experience to support their belief that Rates RTOD-D and RTOD-E are well conceived and that offering these rate choices will benefit customers. But again, it seems hasty to eliminate a proposed offering that might be attractive to some customers, and as an optional rate will not impose harm on any customers. Therefore, I recommend the Commission approve both optional Rates RTOD-D and RTOD-E as proposed.

<u>Now Is the Appropriate Time to Merge LG&E Electric Rates CTODP and ITODP</u>

Q. Why is it appropriate to merge LG&E Rates CTODP and ITODP at this time?

A. The Companies have made concerted efforts over their last four base-rate cases to harmonize their electric tariffs and eliminate commercial and industrial rate classifications, moving instead toward rate classes differentiated solely by service characteristics, and primarily by peak demand. Merging LG&E's Rates CTODP and ITODP is the next-to-last step in fully accomplishing these goals. In working toward that end, LG&E has gradually narrowed the rate differences between Rates CTODP and ITODP over several base-rate cases and have harmonized the rate structure in the most recent base rate proceeding. Although KIUC witness Mr. Baron argues for more forbearance and an even more gradual narrowing of the rate differences, the Companies believe a 4.5% rate increase for Rate ITODP customers—and a 4.5% rate decrease for CTODP customers—is consistent with gradualism.[27] Notably, Mr. Baron says he does not oppose the concept of merging the rates,[28] and he did not oppose the concept in LG&E's 2012 base-rate case when he stated, "While I do not oppose this merger conceptually, I do oppose LG&E's specific proposal to merge these two rates in this case because of the very large, disparate rate increases."[29] The Companies believe enough time has passed, and that the rate differences between Rates CTODP and ITODP are now sufficiently narrow, to make a reality of the concept Mr. Baron says he supports. Therefore, I recommend the Commission approve LG&E's proposed merging of Rates CTODP and ITODP.

<u>The Companies' Commission-Approved Tariff Definition of Industrial for DSM Purposes Comports with Kentucky Statute and Is Broadly Accepted</u>

Q. What is the Companies' current tariffed definition of "industrial" for DSM purposes?

A. The Companies' electric tariffs define "industrial" for DSM purposes as follows:

> For purposes of rate application hereunder, non-residential customers will be considered "industrial" if they are

[27] *See* Baron Testimony at 35-37.
[28] *Id.* at 35.
[29] *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity, Approval of Ownership of Gas Service Lines and Risers, and a Gas Line Surcharge*, Case No. 2012-00222, Testimony of Stephen J. Baron at 27 (Oct. 3, 2012).

> primarily engaged in a process or processes that create or change raw or unfinished materials into another form or product, and/or in accordance with the North American Industry Classification System [NAICS], Sections 21, 22, 31, 32, and 33. All other non-residential customers will be defined as "commercial."[30]

LG&E's gas tariff incorporates by reference the same definition of "industrial."[31] As Mr. Malloy addresses at length in his rebuttal testimony, the Companies' tariff definition of "industrial" contains two criteria: (1) whether a customer engages in a process or processes that create or change raw or unfinished materials into another form or product; and (2) whether the customer has one of five NAICS two-digit codes. As Mr. Malloy further discusses, the Companies employ both criteria when determining whether a customer contract is industrial for DSM purposes, and that it is possible for a customer not to have one of the five NAICS codes listed in the Companies' tariffs and still have a contract the Companies classify as industrial for DSM purposes because the contract serves "a process or processes that create or change raw or unfinished materials into another form or product." Indeed, as Mr. Malloy notes, the Companies have 125 such contracts.

Q. Has the Commission repeatedly approved the Companies' tariffs containing the Companies' current definition of "industrial" for DSM purposes?

A. Yes, the Commission has approved the Companies' definition of "industrial" for DSM purposes in four different sets of proceedings over the course of almost five years. The Companies first proposed, and the Commission first approved, the Companies' current definition of "industrial" in the Companies' 2009 base-rate cases (Case Nos. 2009-00548

[30] Louisville Gas and Electric Company P.S.C. Electric No. 9, First Revision of Original Sheet No. 86; Kentucky Utilities Company P.S.C. No. 16, Fourth Revision of Original Sheet No. 86.

[31] Louisville Gas and Electric Company P.S.C. Gas No. 9, First Revision of Original Sheet No. 86 ("Any industrial gas customer who also receives electric service from the Company as an industrial customer, and has elected not to participate in a demand-side management program hereunder, shall not be assessed a charge pursuant to this mechanism.").

(KU) and 2009-00549 (LG&E)).[32] The Commission subsequently approved the Companies' tariffs containing the "industrial" definition in two DSM Program Plan cases (Case Nos. 2011-00134 and 2014-00003) and in the Companies' 2012 base-rate cases (Case Nos. 2012-00221 and 2012-00222).[33]

Incidentally, the Companies' electric tariffs have also contained the same definition of "industrial" for classifying customers for other purposes since the Companies' 2009 base-rate cases.[34] This has little practical effect now that the Companies have eliminated all industrial rates except LG&E's Rate ITODP, which LG&E has proposed to eliminate in these proceedings. Nonetheless, it is a tariff provision the Commission has twice approved for both Companies.

Q. Is the Companies' definition of "industrial" consistent with KRS 278.285(3) and ratemaking principles in Kentucky?

A. Yes. Contrary to Mr. Chriss's assertion that the Companies' definition of "industrial" for DSM purposes is "inconsistent with the ratemaking process and its results are unreasonably arbitrary and unduly discriminatory," the Companies' definition comports with the relevant

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[32] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Base Rates*, Case No. 2009-00548, Order (July 30, 2010); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*, Case No. 2009-00549, Order (July 30, 2010).

[33] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New Demand-Side Management and Energy-Efficiency Programs*, Case No. 2011-00134, Order (Nov. 9, 2011); *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2012-00221, Order (Dec. 20, 2012); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity, Approval of Ownership of Gas Service Lines and Risers, and a Gas Line Surcharge*, Case No. 2012-00222, Order at (Dec. 20, 2012); *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy-Efficiency Programs*, Case No. 2014-00003, Order (Nov. 14, 2014).

[34] *See* Louisville Gas and Electric Company P.S.C. Electric No. 9, First Revision of Original Sheet No. 101.2; Kentucky Utilities Company P.S.C. No. 16, Fourth Revision of Original Sheet No. 101.2.

portion of Kentucky's DSM statute and is consistent with ratemaking principles in Kentucky.[35]

First, as noted above, the Commission has repeatedly approved the Companies' tariffs in the last five years with the current "industrial" definition; presumably the Commission would not have done so if the definition somehow violated "the ratemaking process" or produced "unreasonably arbitrary and unduly discriminatory" results.

Second, notwithstanding Mr. Chriss's claim that "why a customer takes service or what the customer does with the power is not a functionally necessary part of the ratemaking process,"[36] KRS 278.030(3) states that utilities may employ customer classifications that "take into account **<u>the nature of the use</u>**, the quality used, the quantity used, the time when used, **<u>the purpose for which used</u>**, and any other reasonable consideration."[37] It is true that the Companies have generally moved toward rate classes based on average annual peak demand, which in turn tend to reflect the Companies' cost of service. But differentiating between customers based on the purpose for which customers use utility service is statutorily permissible in Kentucky.

Third, KRS 278.285(3) clearly distinguishes industrial customers from all other customer classes:

> The commission shall allow individual **<u>industrial</u>** customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs if the alternative measures by these customers are not subsidized by other customer classes. Such individual **<u>industrial</u>**

[35] Chriss KU Testimony at 19; Chriss LG&E Testimony at 17.
[36] Chriss KU Testimony at 20; Chriss LG&E Testimony at 18.
[37] Emphases added.

> customers shall not be assigned the cost of demand-side management programs.[38]

Particularly because the statute uses "industrial" as the first criterion for opting out of DSM programs and charges, but also because KRS 278.285(3) requires that DSM program costs be assigned to customer classes that benefit from DSM programs, the Companies needed to define "industrial" for DSM purposes. Because the statute goes on to distinguish industrial customers with energy-intensive processes from industrial customers without such processes, the Companies believe it is reasonable to infer that defining "industrial" for DSM purposes can, and arguably should, depend on the nature or purpose of the customers' use;, defining "industrial" based on the nature or purpose of use, with "energy-intensive" to be defined based on one or more service characteristics, such as demand or consumption is a reasonable interpretation.

The Companies are not arguing that theirs is the only permissible definition of "industrial" for DSM purposes in Kentucky, but it certainly is a permissible definition. It does not violate ratemaking principles as prescribed by Kentucky statute, and neither is it "unreasonably arbitrary or unduly discriminatory"; rather, it comports with a plain-language reading of the applicable statutes, and the Commission has repeatedly approved tariffs containing it.

Q. Are there other reasons to believe the Companies' definition of "industrial," including its use of NAICS codes as one criterion in the definition, is reasonable for DSM purposes?

A. Yes. Notably, the only other Kentucky-statutory definition of "industrial" of which the Companies are aware is comparable to the first criterion of the Companies' definition:

[38] KRS 278.285(3) (emphases added).

> Industrial entity means any corporation, partnership, person, or other legal entity, whether domestic or foreign, which will itself or through its subsidiaries and affiliates construct and develop a manufacturing, processing, or assembling facility on the site of an industrial development project financed pursuant to this chapter[.][39]

The U.S. Energy Information Administration ("EIA"), a division of the U.S. Department of Energy, also uses a definition of "industrial" that comports with the Companies' tariff definition, including the Companies' use of NAICS codes:

> Industrial sector: An energy-consuming sector that consists of all facilities and equipment used for producing, processing, or assembling goods. The industrial sector encompasses the following types of activity: manufacturing (NAICS codes 31-33); agriculture, forestry, and hunting (NAICS code 11); mining, including oil and gas extraction (NAICS code 21); natural gas distribution (NAICS code 2212); and construction (NAICS code 23). Overall energy use in this sector is largely for process heat and cooling and powering machinery, with lesser amounts used for facility heating, air conditioning, and lighting. Fossil fuels are also used as raw material inputs to manufactured products. Note: This sector includes generators that produce electricity and/or useful thermal output primarily to support the abovementioned industrial activities.[40]

Note that the Companies' definition uses only five of the seven NAICS sector codes EIA's definition employs. But even if the Companies adopted EIA's definition, Wal-Mart would not meet the criteria to be classified as industrial for DSM purposes.

The Companies' definition comports also with ordinary dictionary definitions of "industrial," such as this definition from Merriam-Webster's online dictionary:

> : of or relating to industry : of or relating to factories, the people who work in factories, or the things made in factories

[39] KRS 56.440(6).

[40] Energy Information Administration, Electric Power Monthly, January 2015. *Available at:* http://www.eia.gov/electricity/monthly/pdf/epm.pdf. Viewed on February 25, 2015.

> : having a developed industry : having factories that actively make a product
>
> : coming from or used in industry : made or used in factories; also : stronger than most other products of its kind[41]

The consistency of the Companies' definition of "industrial customer" with Kentucky statutory regulatory law, at least one federal definition, and at least one ordinary dictionary definition bespeaks its reasonableness. Mr. Chriss has not provided any authorities or other support for his argument for a change from the Companies' current tariff definition of "industrial" for DSM purposes.

Q. Are the Companies aware of any state statutes or regulations that define "industrial" for DSM purposes?

A. After conducting 50-state research (including the District of Columbia), the Companies are aware of only one state that defines "industrial" for DSM purposes: Indiana defines an "industrial customer" to be "a person that receives services at a single site constituting more than one (1) megawatt of electric capacity from an electricity supplier."[42] Notably, Indiana allows all industrial customers to opt out of utility-sponsored DSM-EE programs and charges, not a subset of industrial customers as does KRS 278.285(3). It is also noteworthy that none of Wal-Mart's locations in the Companies' service territories would qualify as an industrial customer under Indiana's statutory definition if an annual-average-of-monthly-peaks approach were applied to determine the demand necessary to meet the test.

Q. Mr. Chriss argues against the Companies "industrial" definition in part because the NAICS codes it employs in one of its two criteria do not include "customers such as

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[41] http://www.merriam-webster.com/dictionary/industrial. Viewed on February 25, 2015.
[42] Indiana Code 8-1-8.5-9(e).

data centers (NAICS Section 51) and distribution centers (NAICS Section 48-49), that are energy intensive and would traditionally be thought of as 'industrial.'"[43] Are you aware of any definition of "industrial" that would include data centers and distribution centers?

A. No, I am not aware of such a definition; the Kentucky statutory, federal regulatory, and dictionary definitions I provided above would not encompass such facilities. Indeed, Mr. Chriss offers only his bare assertion to support for his claim that data centers and distribution centers "would traditionally be thought of as 'industrial.'" Without more support for his claim than that, the Commission should not concede Mr. Chriss's assertion that a traditional definition of "industrial" would encompass data centers and distribution centers.

Q. Mr. Chriss argues against any use of NAICS codes in the Companies' definition of "industrial" for DSM purposes based in part on a North Carolina Utilities Commission ("NCUC") order.[44] Does the cited NCUC order have any bearing on the Companies' tariff definitions in Kentucky?

A. No, it does not. The portion of the NCUC order Mr. Chriss quotes in his testimony gives the misimpression that the reason the NCUC ordered Duke North Carolina to combine certain rates was solely because SIC codes (predecessor codes comparable to NAICS codes) do not provide an adequate reason to have different rates for similarly situated customers:

> The Commission is concerned with the impact of increasing Schedule OPT-I and OPT-H rates. However, the Commission is also concerned with the reasonableness and

[43] Chriss KU Testimony at 22; Chriss LG&E Testimony at 19.

[44] Chriss KU Testimony at 22; Chriss LG&E Testimony at 20. The cited NCUC order is Order Granting General Rate Increase, North Carolina Docket No. 15 E-7, Sub 989, January 27, 2012 ("NCUC Order").

> fairness of maintaining a differential between Schedules OPT-I/OPT-H and Schedule OPT-G based largely on labels such as the SIC codes. Thus, the Commission concludes that steps toward potentially recombining the OPT-I, OPT-H and OPT-G rates in an equitable manner should begin now ….[45]

But the NCUC stated earlier in its order that the arguments it considered in coming to the conclusion above were that similarly situated commercial and industrial customers should not have different rates, and that government facilities should not have different rates than similarly situated industrial customers.[46] Also, availability of the more favorable industrial rate at issue in that proceeding depended solely on SIC codes; "industrial" was defined only by using SIC codes.[47]

The reasons the NCUC order do not apply to the Companies' "industrial" definition are plain and clear. First and most important, although the NCUC apparently had the discretion to determine that whether a customer was industrial was irrelevant for rate-availability in that case, KRS 278.285(3) does not afford this Commission the same discretion; the statute specifically singles out "industrial customers." The term must be defined, and presumably it must mean something different from "residential" or "commercial" if it is to mean anything at all.

Second, as Mr. Malloy and I have testified and as the Companies' tariffs clearly state, NAICS codes are one of two criteria the Companies use to classify customers as industrial or commercial for DSM purposes. As Mr. Malloy's testimony states, the Companies have customer contracts classified as industrial for DSM purposes that meet the first criterion and have either no NAICS code or have an NAICS code other than one

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[45] NCUC Order at 48.
[46] NCUC Order at 47-48.
[47] *Id.*

of the five listed in the Companies' tariffs. Also, the Companies have a number of customer contracts associates with one of the NAICS codes listed as industrial in their tariffs because the particular contracts do not serve industrial processes as defined in the Companies' tariffs. So Mr. Chriss's single-issue attack on the Companies' use of NAICS codes is really an assault on a straw man like argument; the reality of how the Companies define "industrial" is not what the bulk of Mr. Chriss's testimony portrays it to be.

Q. Do the Companies allow customers classified as industrial for DSM purposes to opt out of the Companies' DSM programs?

A. No. It is important to distinguish between being classified as industrial for DSM purposes and having a right under KRS 278.285(3) to opt out of applicable DSM programs and charges. The only thing the Companies' tariffs define today is what "industrial" means for DSM purposes. The Companies' customer contracts classified as industrial do not pay DSM charges today only because the Companies currently do not offer DSM programs to industrial customers.

But if that were to change, the Companies currently have no customers who have opted out of DSM programs and charges; indeed, the Companies currently have no guidelines or procedures for opt-outs. To establish opt-out guidelines and procedures would require taking into account the four different criteria KRS 278.285(3) establishes:

> The commission shall allow individual [1] industrial customers [2] with energy intensive processes [3] to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs if [4] the alternative measures by these customers are not subsidized by other customer classes.

The only topic at issue in this proceeding related to DSM, according to the relevant Commission order, is the Companies' use of NAICS codes as one of its criteria for classifying customers as industrial for DSM purposes: "During the next general rate case for the Companies, we will review the Companies' definition of industrial customers by NAICS codes for reasonableness."[48] That issue concerns only part of the first criterion of the four requirements to be met for opt-outs; how a customer might meet all criteria to opt out of applicable DSM programs is not at issue in this proceeding. Therefore, Mr. Chriss's testimony concerning DSM-opt-out eligibility is simply irrelevant.[49]

Q. Citing Oklahoma law, Mr. Chriss appears to recommend that the Commission should classify as industrial for DSM purposes any non-residential entity that has an annual aggregate energy usage of 15 million kWh across of its sites in a state.[50] Do you agree that this is a permissible approach in Kentucky?

A. No, it is not a permissible approach in Kentucky. Mr. Chriss cites two Oklahoma utilities as permitting customers with annual aggregated energy usage of 15 million kWh or more to opt out of their DSM programs and associated charges.[51] But the Oklahoma law that supports the cited tariffs does not mention or define "industrial" or "industrial customers"; indeed, Oklahoma's administrative regulations governing DSM opt-outs do not refer to customer classes at all, industrial or otherwise. Instead, they define "high-volume electricity usage" to be "consumption by a single customer in Oklahoma of more than 15 million kWh of electricity per year, regardless of the number of meters or service

[48] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy-Efficiency Programs*, Case No. 2014-00003, Order at 26 (Nov. 14, 2014).
[49] Mr. Chriss's testimony explicitly addressing opt-out eligibility is at Chriss KU Testimony page 21 and Chriss LG&E Testimony page 19.
[50] Chriss KU Testimony at 20-21; Chriss LG&E Testimony at 18.
[51] Chriss KU Testimony at 21 n.3; Chriss LG&E Testimony at 18 n.3.

locations."[52] In turn, they permit high-volume electricity users to opt out of DSM programs and charges, regardless of a high-volume electricity user's customer class:

> Demand portfolios shall:
>
> …
>
> (11) Allow any high-volume electricity user, after the utility has a reasonable opportunity to present customized opportunities to such user, to opt out of some or all energy efficiency or demand response programs by submitting notice of such decision to the director of the Public Utility Division and to the electric utility that submits the demand portfolio.[53]

Mr. Chriss's indirect appeal to Oklahoma's administrative regulations to interpret Kentucky's DSM statute is therefore inapposite because the question before the Commission in this proceeding is whether the Companies' use of NAICS codes as one of two criteria to define "industrial" is appropriate, a topic Oklahoma's regulations simply do not address because they do not define or use "industrial." The Oklahoma regulations and cited tariffs are therefore irrelevant to this proceeding.

But even if the Oklahoma standard were somehow relevant to this proceeding, it would be an impermissible approach in Kentucky because meter aggregation is prohibited by Commission regulation:

> The utility shall regard each point of delivery as an independent customer and meter the power delivered at each point. Combined meter readings shall not be taken at separate points, nor shall energy used by more than one (1) residence or place of business on one (1) meter be measured to obtain a lower rate.[54]

[52] OAC 165:35-41-3.
[53] OAC 165:35-41-4(b).
[54] 807 KAR 5:041 Sec. 9(2).

Presumably Wal-Mart would not favor applying the 15-million-kWh-per-year test on a disaggregated basis because none of its facilities would meet the requirement.

But in addition to being impermissible, the 15-million-kWh-per-year test is facially unrelated to any rational definition of industrial, and practically would lead to bizarre results. For example, in calendar year 2014 the Companies had over 130 customer contracts with usage over 15 million kWh. The majority of those contracts are undeniably industrial under any reasonable definition. But the list also includes hospitals and university campuses. As important as those facilities are, they are not industrial. The test does not meet its intended purpose, and cannot define "industrial"; the Commission should reject it.

<u>There Is No Cost-of-Service Basis for Expanding Rate AES or Creating a Sports Field Lighting Rate</u>

Q. Please explain why there is no cost of service basis for reopening KU's Rate AES or adding a Rate AES rate schedule to LG&E's electric tariff.

A. KU implemented its existing Rate AES decades ago to promote the building of all-electric schools. Over the course of several base-rate cases, KU has worked to have the rate more closely reflect the cost of service for customers on the rate; with the rates proposed in these proceedings, KU has effectively accomplished that goal. But KU has consistently sought to freeze the rate, too, recognizing that the rate does not comport with cost-of-service principles. Applying any rate, including Rate AES, to a rate class that is not reasonably homogeneous fails to send customers accurate price signals and supports cross-subsidization.

Simply put, there is no cost-of-service justification for a special rate for schools. Different schools have different service characteristics, which the different rates under which schools now take service under the Companies' tariffs demonstrate. But more importantly, schools with particular service characteristics do not differ significantly from other customers taking service under the same rates. Further complicating the aligning of the cost of service and the recovery of those costs is the diversity of loads to which the simple structure of Rate AES is applied; loads served under Rate AES comprise not only class rooms, offices, cafeterias, and gymnasiums, but also garages, pumps, sports-field lighting, storage sheds, pumps, and traffic lights. For small customer groups with significant variation in delivery voltages, loads, and load patterns, a single rate schedule is not appropriate. Therefore, creating a new Rate AES for LG&E would likely, if not certainly, violate cost-of-service principles.

In sum, the Companies do not support adding a Rate AES to LG&E's tariff, and do not believe it is appropriate to reopen KU's Rate AES to new loads, because there is no cost-of-service justification for either action.

Q. Does the same cost-of-service-based objection apply to Mr. Willhite's sports-field-lighting-rate proposal?[55]

A. Yes, it does. There is no evidence—certainly none has been supplied in these proceedings—to show that the cost of serving sports fields, including lighting, locker rooms, concession stands, and ticket offices, is markedly different than the cost of serving non-residential customers with similar demands. In particular, there is no evidence that all such usage occurs during off-peak hours; indeed, it is reasonable to expect that non-lighting (and perhaps also lighting) sports-field facilities would operate during daytime, on-peak hours. Moreover, the Companies recently set their all-time combined-system peak load in

[55] Willhite KU Testimony at 11-12; Willhite LG&E Testimony at 11-13.

January 2014 when it was dark outside—during traditionally off-peak hours. Without a clear cost-of-service justification for creating a new special rate schedule just for sports fields—and the Companies do not believe one exists—the Commission should deny KSBA witness Mr. Willhite's request to direct the Companies to add a sports-field-lighting rate to each of their electric tariffs.

<u>The Companies' Current Rate CTAC Charges for Pole Attachments Are Reasonable and Comply with the Commission's Relevant Order in Administrative Case No. 251</u>

Q. Are there any issues raised in the testimony of Ms. Kravtin you would like to address?

A. Yes. Although Dr. Blake's testimony thoroughly addresses Ms. Kravtin's testimony, I would like to comment on three issues she raises. First, the Commission has previously explicitly approved LG&E's applying its full rate of return (what Ms. Kravtin calls a net rate of return) to its gross pole plant to calculate LG&E's levelized carrying charge and ultimately its pole attachment rate; therefore, in addition to Dr. Blake's arguments supporting applying the Companies' full rates of return for this purpose, there is also clear Commission precedent to support it.[56]

Second, Ms. Kravtin asserts the Companies' Rate CTAC charges do not meet the requirements of the Commission's order in Administrative Case No. 251 because they did not apply a 15% discount to bare pole costs to deduct the value of minor appurtenances. But Dr. Blake provides calculations of what Rate CTAC charges would have been justified if the Companies had sought to change them in this proceeding using a 15% deduction for minor appurtenances while also accounting for other costs that should be included when formulating pole-attachment charges; his calculations show the Companies would have

[56] *In the Matter of: Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company*, Case No. 1990-00158, Order at 70 (Dec. 21, 1990) ("The pole attachment charges proposed by LG&E, modified to reflect the overall rate of return of 9.89 percent, are granted.").

proposed increased, not decreased, Rate CTAC charges. The methodology Dr. Blake uses to calculate the charges—which the Companies are presenting only to rebut Ms. Kravtin, not to propose changes to the charges—is fully consistent with the relevant order in Administrative Case No. 251, which permits cost-justified deviations from the standard formula the order provides.[57] Therefore, the Companies' current Rate CTAC charges are reasonable, and I recommend the Commission leave them unchanged.

Third, Ms. Kravtin somewhat oddly included in her testimony calculations of what she believed the Companies' Rate CTAC charges should have been beginning on January 1, 2013, following the Commission's final orders in the Companies' 2012 base-rate cases. Perhaps she included the calculations purely to show how unjust KCTA believes the Rate CTAC charges have been since then. But a more likely explanation is that she was attempting to build an evidentiary record to support KCTA's claims for a refund since that time, a refund KCTA was seeking in a rate-complaint case, Case No. 2014-00025; KCTA had asked the Commission to consolidate that proceeding with these proceedings. On March 27, 2015, the Commission issued an order dismissing the complaint with prejudice and denying KCTA's request to consolidate that proceeding with these proceedings on the straightforward ground that the Commission cannot grant retroactive rate relief.[58] The Commission further stated, "[P]ursuant to 278.270, any relief to which KCTA might be entitled in this complaint case can be only prospective in nature, which is the same type of

[57] *In the Matter of: The Adoption of a Standard Methodology for Establishing Rates for CATV Pole Attachments*, Admin. Case No. 251, Order at 16-17, (Aug. 12, 1982) ("The Commission will allow deviations from the mathematical elements found reasonable herein only when a major discrepancy exists between the contested element and the average characteristics of the utility, and the burden of proof should be upon the utility asserting the need for such deviation[.]").

[58] *In the Matter of: Kentucky Cable Telecommunications Association v. Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2014-00025, Order at 11 (Mar. 27, 2015).

relief that can be awarded in the pending rate cases."[59] Therefore, Ms. Kravtin's calculations of what she believes the Companies' Rate CTAC charges should have been since January 2013 are irrelevant to these proceedings and should be disregarded.

Q. Did the Companies comply with the instructions KCTA gave in its data requests concerning providing information for the future test year?

A. Yes. In its responses to the Commission Staff's data requests, KCTA attempts to shift responsibility to the Companies for KCTA's failure to calculate proposed Rate CTAC charges based on future-test-year data; for example:

> KCTA further responds that, in both its First and Supplemental Data Requests, it instructed Louisville Gas and Electric Company ("LG&E") to provide data for the forecasted time period ending June 30, 2016 to the extent it relies on the forecasted data to support its pole attachment rates. See KCTA First Data Requests, Instruction No. 6; KCTA Supplemental Data Requests, Instruction No. 7. LG&E did not provide any data for the forecasted period.[60]

But as KCTA notes in the quote above, KCTA's instructions asked the Companies to provide forecasted data <u>to the extent they relied on forecasted data to support their pole attachment rates</u>. Of course, because the Companies have not proposed to change their Rate CTAC charges in these proceedings, their existing Rate CTAC charges—which are the charges the Companies propose to keep in place—are not based on forecasted data; rather, they were based on the historical data presented in the Companies' 2012 base-rate cases, cases in which KCTA did not seek to intervene. So the Companies followed precisely the data-request instructions KCTA provided, their insinuations to the contrary notwithstanding.

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[59] *Id.*

[60] Kentucky Cable Telecommunications Association Responses to the Commission Staff's Data Requests in Case No. 2014-00372, Response to Request 1(a) (Apr. 6, 2015).

Moreover, KCTA was permitted, and actually issued, two rounds of discovery in these proceedings. Had KCTA requested to have forecasted data, or if it believed the Companies had failed to comply with KCTA's first-round instructions, KCTA could have requested forecasted data in the second round of discovery. For whatever reason, they did not do so. But that was their prerogative; the responsibility for their decision is theirs, not the Companies'.

Q. Do you have a final comment in general about the claims raised in the testimony of Ms. Kravtin you would like to address?

A. Yes. KCTA through the testimony of Ms. Kravtin seeks a substantial prospective reduction in the current Rate CTAC for pole attachments. The revenues from Rate CTAC are miscellaneous revenues that reduce the revenue requirement needed from the Companies' other customers. To the extent that Rate CTAC is reduced, the reduction in revenue must be allocated to the other rate classes for ratemaking purposes and will increase the revenue requirement from all other customer classes. This reduction should be spread across the other rate classes on the cost-of-service allocator. In doing so, the difference will be borne by other customers.

Recommendation and Conclusion

Q. What is your recommendation to the Commission?

A. Because the Companies' proposed rates—including the Companies' proposed residential Basic Service Charges—are based on the Companies' cost of service and are necessary for the Companies to continue providing safe and reliable service at the lowest reasonable cost, I recommend the Commission approved the Companies' applications as filed.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Director - Rates for Louisville Gas and Electric Company and Kentucky Utilities Company, 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

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of April 2015.

______________________ (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In Re the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2014-00371**

In Re the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2014-00372**

REBUTTAL TESTIMONY OF
DR. MARTIN BLAKE
PRINCIPAL
THE PRIME GROUP, LLC

Filed: April 14, 2015

Table of Contents

Exhibits

Rebuttal Exhibit MJB-1	- Calculation of LGE Attachment Charges for CATV Using Administrative Case No. 251 Methodology
Rebuttal Exhibit MJB-2	- Calculation of KU Attachment Charges for CATV Using Administrative Case No. 251 Methodology
Rebuttal Exhibit MJB-3	- Demonstration of Kravtin's Use of Different Discount Rates
Rebuttal Exhibit MJB-4	- Correction of Kravtin's Use of Different Discount Rates
Rebuttal Exhibit MJB-5	- Calculation of LGE Attachment Charges for CATV Using All Relevant Costs
Rebuttal Exhibit MJB-6	- Calculation of KU Attachment Charges for CATV Using All Relevant Costs

Q. Please state your name and business address.

A. My name is Martin J. Blake. My business address is 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky 40014.

Q. Are you the same Martin J. Blake who filed Direct Testimony on behalf of Kentucky Utilities Company and Louisville Gas and Electric Company ("KU", "LGE" or "Companies") in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review the Testimony that was filed by Mr. Paul Chernick, Mr. Ronald Willhite, Mr. Stephen Baron, Mr. Steve Chriss and Ms. Patricia Kravtin in Case Nos. 2014-00371 and 2014-00372 on March 6, 2015 and to correct and rebut any inaccuracies or inconsistencies in their Testimony.

Residential Electric Basic Service Charges

Q. Does Mr. Chernick's Testimony recognize what properly constitutes a fixed cost and that there are both volumetric and non-volumetric components of fixed cost?

A. No. Mr. Chernick's recommendation regarding the basic service charge is based on a misconception of what constitutes fixed distribution cost, and a misconception of what is included in the volumetric and non-volumetric components of fixed distribution costs. In his Direct Testimony, Mr. Chernick states that "(t)he Company lacks a reasonable basis for its plan to shift allegedly 'fixed' costs from the residential energy charge to the basic service charge."[1] But once meters, services, transformers, poles and conductor are installed to meet customer needs, these distribution costs that have been incurred by the Companies are recorded in the Companies' FERC system of accounts and will not change. Because costs that do not change meet the definition of fixed costs, these distribution costs that have been incurred by the Companies are clearly fixed costs.

Q. Why do you believe that Mr. Chernick does not understand the volumetric and non-volumetric components of existing fixed distribution costs?

A. In his Direct testimony, Mr. Chernick states that "Dr. Blake apparently recognizes the distinction between fixed costs that vary over the long run with customer usage (i.e., "volumetric" demand-related costs) and those that do not (i.e., "non-volumetric" customer-related costs)."[2] This is not what I mean when I classify existing fixed distribution costs as either volumetric or non-volumetric, and the classification of costs as volumetric in the cost of service study in this proceeding has nothing to do with the long run when additional fixed costs may be incurred in the future. The Companies' existing fixed distribution costs have both a volumetric and a non-volumetric component. Non-volumetric fixed distribution costs are classified as customer-related distribution costs and include the cost of the minimum set of existing distribution facilities necessary to provide a customer with access to the electric grid. This

1 Chernick Direct Testimony, Case No. 2014-00371, 3:4-5 and Case No. 2014-00372, 3:4-5
2 Chernick Direct Testimony, Case No. 2014-00371, 5:24 through 6:3 and Case No. 2014-00372, 5:24 through 6:3

minimum set of distribution facilities consists of a meter, service drop, transformer and some minimum amount of poles and conductor without which the customer would not be able to purchase electric energy from the Companies. Volumetric fixed distribution costs are classified as demand-related distribution costs and are related to the size of the existing distribution equipment that the Companies had to install to reliably meet the customer's needs. Even though this size related portion of existing fixed distribution costs is determined by the size of the load that customers have placed on the system, they are nonetheless fixed costs for the Companies as they reflect existing distribution equipment that is currently installed, not fixed costs that may be incurred in the future and that are not yet booked in the Companies' accounts. Mr. Chernick's concept of volumetric fixed costs is totally inaccurate as the costs to which he refers have not yet been incurred, may be incurred in the future and thus, are not fixed. His flawed discussion of demand-related and customer-related fixed distribution costs is based on this misconception. An illustration of his application of this misconception is contained in footnote 4 in his Direct Testimony which states that "shifting recovery of volumetric fixed costs to the basic service charge could further and needlessly increase basic service charges <u>in the future</u>, in order to recover uneconomic plant investment required to meet <u>demand growth</u> resulting from misleading price signals."[3] (emphasis added). Because his recommendations regarding the basic service charge are based on a flawed conception of the volumetric and non-volumetric components of existing fixed

3 Chernick Direct testimony, Case No. 2014-00371, Footnote 4, page 6 and Case No. 2014-00372, Footnote 4, page 6

distribution costs in the cost of service studies submitted by the Companies, they should be ignored by the Commission.

Q. Is this classification of existing fixed distribution costs into demand-related and customer-related components widely accepted in the industry?

A. Yes. This split between customer-related and demand-related fixed distribution costs is recognized in the NARUC Electric Utility Cost Allocation Manual which states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.[4]

In order to be booked into Accounts 364 through 370, the costs had to have already been incurred, and thus are existing fixed distribution costs. The Companies chose to use the zero-intercept method rather than the minimum-size-of-facilities method in classifying existing fixed distribution costs as either customer-related or demand-related.

Q. Why did the Companies choose to use the zero-intercept method for classifying existing fixed distribution costs as either demand-related or customer-related costs?

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4 Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January, 1992, p. 90.

A. The Companies chose to use the zero-intercept method in classifying existing fixed distribution cost as either customer-related or demand-related because this methodology has been used by the Companies and accepted by the Commission in prior rate cases and also avoids the problem of classifying some customer-related costs as demand-related. This problem of classifying some customer-related costs as demand-related can be summarized as:

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.[5]

The use of the zero-intercept methodology avoids classifying some demand-related costs as customer-related and is the method preferred by the Companies for classifying existing fixed distribution costs in the cost of service study.

Q. Do you agree with Mr. Chernick's statement that the basic service charge is intended to reflect the incremental costs imposed by the continued presence of a customer who uses very little energy?

A. No. The basic service charge is designed to recover the cost of installing, operating and maintaining the minimum set of equipment necessary to provide a customer with access to the electric grid and is comprised of costs classified as non-volumetric fixed costs. The non-volumetric fixed distribution cost per customer, on which the basic service

5 Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January, 1992, p. 95.

charge is based, is properly calculated on an average basis rather than on an incremental basis as proposed by Mr. Chernick. The incremental approach proposed by Mr. Chernick would allow new customers to use existing facilities that have previously been installed to meet customer needs without spreading these fixed costs over all customers served by the existing facilities, including the new customers, as is typically done in developing electric utility rates.[6] Spreading the fixed cost of the minimum set of facilities necessary to serve a customer over all customers would require an average calculation of the cost rather than an incremental calculation of the cost as proposed by Mr. Chernick.

Q: Do you agree with Mr. Chernick's assertion that the non-volumetric distribution cost will vary depending upon the size of the customer's load?

A: No. Mr. Chernick states that "the minimum distribution cost per customer will vary with the usage of the customers served by the distribution equipment. Consequently, the true minimum cost to serve a customer with very little usage is likely to be less than the non-volumetric fixed cost per customer."[7] (emphasis added) Mr. Chernick is incorrectly attempting to bring size into the development of a cost that is meant to convey the cost of providing service that is not size related. The customer-related, non-volumetric fixed distribution cost of providing service to a customer represents the cost

6 Sierra Club Response to LGE-8 which states that "Incremental costs of adding a customer would not include a transformer, because most residential customers do not require a separate transformer, other than to accommodate their load level. Thus, while increasing load by more than a threshold amount would require adding or upgrading a transformer, adding a new customer while keeping load constant would not trigger this need."

7 Chernick Direct Testimony, Case No. 2014-00371, 8:17-21 and Case No. 2014-00372, 8:19-23

of the set of distribution facilities that any customer must have that has no load carrying capability at all, and thus, are not related to the size of the customer's load. It represents zero kVA transformers and zero MCM conductors. By definition, an asset that has no size related characteristics cannot change with the size of the customer. The demand-related portion of the costs represents the costs that vary with the size of the customers load. If the Commission were to adopt Mr. Chernick's recommendation, it would defeat the purpose of splitting costs between customer-related and demand-related cost components in the cost of service study.

Q: Is Mr. Chernick's estimate of the incremental cost to connect a customer an accurate representation of the actual incremental cost of connecting a customer to the system?

A: No. On pages 11 and 12 of his testimony, Mr. Chernick discusses his estimate of the incremental cost of connecting a customer to the system. The cost of service studies submitted by the Companies do not contain any marginal or incremental costs and cannot be used to determine the marginal or incremental cost of providing service. Mr. Chernick seems to understand this concept in spite of his assertion that he estimated the incremental costs of connecting a customer to the system. Mr. Chernick states that "(t)he Company COSS classifies the costs of the Company's existing system between demand-related and energy-related components, and allocates those embedded costs among classes. The COSS is not designed to estimate the incremental costs of serving an additional kilowatt-hour on peak versus off-peak."[8] While I strongly disagree with the argument that the customer charge should recover the marginal cost of connecting a customer to the system, if the customer charge were to be based on this concept, Mr. Chernick's calculation would be the incorrect method for calculating it.

Q. Do you agree with Mr. Chernick's calculation of the basic service charge?

A. No. Chernick Exhibit PLC-2 contains a flawed calculation of the basic service charge. Mr. Chernick claims that the basic service charge should only include installation and maintenance costs for a service drop and meter, along with meter-reading, billing, and other customer service expenses.[9] Mr. Chernick does not explain how a customer could purchase electric energy without a transformer and some minimum amount of poles and conductor, which might justify the omission of this equipment from the basic service charge. Mr. Chernick's calculation of the basic service charge is also inconsistent with the NARUC Electric Utility Cost Allocation Manual which makes it clear that some minimum amount of poles, conductor and transformer should be included in the non-volumetric customer-related distribution costs that are included in the calculation of the basic service charge.[10] Mr. Chernick argues that cost classification and allocation of fixed distribution costs as customer-related and demand-related should not be used in developing the basic service charge stating that:

> Regardless of the method used to classify and allocate distribution costs among classes (e.g. zero-intercept, minimum-size, demand), it is not appropriate to use

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8 Chernick Direct Testimony, Case No. 2014-00371, 39:14-18 and Case No. 2014-00372, 39:14-18
9 Chernick Direct Testimony, Case No. 2014-00371, 11:11-15 and Case No. 2014-00372, 11:14-18
10 Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, January, 1992, p. 90.

> the allocation of those costs to classes as a basis for rate design and particularly for determining the fixed monthly charge per customer. (Sierra Club response to Data request LGE-6)

This argument is inconsistent with Commission precedent and electric utility industry practice. If the customer-related costs are not used as a basis for developing the fixed monthly basic service charge, there is no reason for making this distinction in the cost of service study in the first place. Thus, Mr. Chernick's calculation of the basic service charge is fatally flawed and his recommendation to maintain the basic service charge at the current level of $10.75 should be disregarded by the Commission.

Q. Do you agree with Mr. Chernick that increasing the basic service charge as the Companies propose would significantly reduce the incentive for customers to conserve?

A. No. Beginning on page 15 of his Direct Testimony in Case No. 2014-00371, Mr. Chernick argues that the increase in the basic service charge proposed by the Companies in conjunction with a decrease in the energy charge would dampen the price signals for conservation. Compared to the proposed basic service charge of $18.00, the current service charge of $10.75 under-recovers customer-related fixed distribution costs by $7.25 per customer per month. When this under-recovery of $7.25 per customer per month is multiplied by the 5,164,164 customer months for KU's residential rate class during the test year, the result is $37,440,189 in non-volumetric customer-related fixed operating expenses and margins that are being "variablized" and recovered through a kWh energy charge rather than being recovered through the basic service charge. When this amount is recovered through the energy charge instead, the result is \$0.006 per kWh of fixed operating expenses and margins collected through the energy charge (calculated as \$37,440,189 / 6,197,389,895 kWh = \$0.006 per kWh). However, this is not a measure of the change in the energy charge that the Companies are proposing for the Residential rate class which is also impacted by the requested rate increase. Although Mr. Chernick claims that the Companies' proposal would result in a reduction of the energy price that would reduce the incentive to conserve energy, KU's proposal would result in an increase from the Company's current energy charge of \$0.07744 per kWh for Residential customers to the new energy charge of \$0.08057 per kWh. Contrary to Mr. Chernick's claim, the energy charge proposed by KU would increase rather than decrease and would not reduce the incentive to conserve energy. Thus, the premise on which Mr. Chernick bases his price elasticity analysis is incorrect, as it is calculated using an energy price decrease rather than the actual proposed energy price increase, and Mr. Chernick's analysis and recommendations should be disregarded by the Commission. Although Mr. Chernick appears to believe that it is a good idea to increase the energy charge in order to provide a stronger incentive for conservation and energy efficiency, he has provided no cost causative reason why this should occur. His recommendation for the basic service charge to remain at \$10.75 and to recover through an energy charge the non-volumetric customer-related fixed distribution costs that are not recovered through the basic service charge appears to be based on his claim that rate design has little or no relationship to equity or cost causation, and that the aim of rate design is to elicit desired customer behaviors.[11] By contrast, the Company's rate design recommendations are based solidly on cost causation, which is usually the standard applied by regulatory commissions in deciding whether rates are fair, just and reasonable.

Q. Do you agree with Mr. Chernick that the basic service charge that the Company is proposing would exacerbate the subsidization of larger residential customers' costs by low-usage customers?

A. No. Mr. Chernick has the direction of the subsidization exactly backwards. Because non-volumetric fixed distribution costs are variablized and collected through the energy charge in the energy component of the current rate charged to Residential customers, customers purchasing more kWh than the class average would be subsidizing the non-volumetric fixed costs of customers purchasing less kWh than the class average, which is exactly opposite of what Mr. Chernick claims.

Q. Would the basic service charge proposed by the Companies recover all non-volumetric fixed costs for the Residential classes?

A. No. For KU, the non-volumetric fixed distribution costs that are classified as customer-related are $21.47 per customer per month. For LGE, the non-volumetric fixed distribution costs that are classified as customer-related are $19.34 per customer per month. The proposed basic service charge of $18.00 per customer per month for both

11 Chernick Direct Testimony, Case No. 2014-00371, 13: 4-15 and Case No. 2014-00372, 13: 7-21where he states that "Once revenue requirements are determined and allocated to classes, the considerations in designing rates are very different from those that drive class cost allocation."

Companies is a move in the direction of cost causative rates, but it does not cover all of the non-volumetric fixed distribution costs that are classified as customer-related.

Q. Do you agree with Mr. Chernick that while it may be reasonable to classify certain load-related costs as customer-related for cost allocation purposes, it does not follow that all such costs should be recovered through a fixed basic service charge?

A. No. Apparently without regard for longstanding Commission precedent, Mr. Chernick states in his Direct Testimony and his responses to the Companies' data requests that, although a utility's cost of service is useful to allocate revenue requirements equitably among rate classes, it is driving customers' behavior that should guide ratemaking.[12] But as Mr. Chernick admits in his responses to the Companies' data requests, he is not aware of any Commission orders explicitly stating that driving customers' behavior should guide ratemaking;[13] I am similarly unaware of any such orders. Instead, in Administrative Case No. 203, the Commission stated, "[T]he cost of service standard of Section 111(d)(l) of PURPA [the federal Public Utilities Regulatory Policy Act of 1978] … [is] the key standard and should be considered separately from the other ratemaking standards."[14] The other ratemaking standards the Commission cited were conservation, utility efficiency, equitable rates, rate continuity, revenue stability, and

12 Chernick KU Testimony at 13; Chernick LG&E Testimony at 13; Responses to KU Data Requests on Behalf of Sierra Club, Response to DR No. 1; Responses to LG&E Data Requests on Behalf of Sierra Club, Response to DR No. 1.

13 Responses to KU Data Requests on Behalf of Sierra Club, Response to DR No. 1; Responses to LG&E Data Requests on Behalf of Sierra Club, Response to DR No. 1.

14 *In the Matter of: The Determinations with Respect to the Ratemaking Standards Identified in Section 111(d)(1)-(6) of the Public Utility Regulatory Policies Act of 1978*, Administrative Case No. 203, Order at 4 (Feb. 28, 1982).

rate understandability.[15] Of those ratemaking standards, the only one the Commission described as "key" was the cost-of-service standard, which stated:

> Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class ….
>
> …
>
> [T]he costs of providing electric service to each class of electric consumers shall, to the maximum extent practicable, be determined on the basis of methods prescribed by the state regulatory authority. … Such methods shall to the maximum extent practicable - (1) permit identification of differences in cost incurrence, for each such class of electric consumers, attributable to daily and seasonal time of use of service and (2) permit identification of differences in cost-incurrence attributable to differences in customer demand, and energy components of cost. In prescribing such methods, such state regulatory authority or non-regulated electric utility shall take into account the extent to which total costs to an electric utility are likely to change if - (a) additional capacity is added to meet peak demand relative to base demand; and (b) additional kilowatt-hours of electric energy are delivered to electric consumers.[16]

The Commission stated concerning the record of Administrative Case No. 203 on the cost-of-service standard, "One of the <u>least</u> disputed propositions advanced during the cost of service hearings was that the conservation, efficiency, and equity purposes of PURPA, as well as the additional objectives of the Commission—adequacy and stability of revenue for the utilities, minimization of economic dislocations from rate changes, acceptance and understanding of rate structures by consumers—are best

15 *See id.* at 4-9.
16 *Id.* at 10.

served by rates that track costs."[17] Concerning the conservation standard, the Commission did not advocate for crafting rates to achieve maximum encouragement of conservation regardless of a utility's cost of service, but rather stated, "Prices which reflect the cost of the resources necessary to produce an additional unit of electricity will encourage conservation."[18] Finally, the Commission stated that, *contra* Mr. Chernick, equity is an important consideration in making rates, not just revenue allocation:

EQUITABLE RATES

> This purpose envisions the promotion of equitable rates for consumers of electricity. <u>The Commission believes that rates based on costs will achieve this purpose</u>, and that payment for the cost consequences of consumption decisions avoids wasteful subsidies among consumers. However, this purpose is not to be construed as requiring equal rates of return among classes of consumers.[19]

So what is clear from the Commission's precedent is that a utility's cost of service is to have paramount sway not just in revenue allocation, but also in rate design. This is fully consistent with the Commission's orders in the Companies' 2012 base-rate cases that Mr. Chernick quotes, "[W]e will strive to avoid taking actions that might disincent energy efficiency";[20] certainly the Commission should not approve rates that

17 *Id.* at 17-18 (emphasis in original).
18 *Id.* at 7.
19 *Id.* at 8 (emphasis added).
20 Chernick KU Testimony at 4, *quoting In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2012-00221, Order at 11 (Dec. 20, 2012); Chernick LG&E Testimony at 4, *quoting In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity, Approval of Ownership of Gas Service Lines and Risers, and a Gas Line Surcharge*, Case No. 2012-00222, Order at 15 (Dec. 20, 2012).

are detrimental to energy-efficiency incentives if the rates have no cost-of-service basis. This is also consistent with the Commission's statement in a 2009 order, "[T]he Commission is very much interested in cost-of-service-based rates and demand-side management programs that incentivize both the utility and customers to practice energy efficiency in a cost-effective manner."[21]

What is further clear is that the Companies' proposed residential Basic Service Charges advance what the Commission has called the key consideration in designing rates; they are closer to the total customer-related costs shown in the Companies' cost-of-service studies. As I noted above, achieving this move toward the Commission's key rate-design objective will have no material effect on customers' energy-efficiency incentives, but it will also advance the Commission's equity goals by reducing intra-class subsidy between high-usage and low-usage residential customers. This advancing of the Commission's interest in equitable rates with no material effect on conservation incentives accords with the Commission's statement in Administrative Case No. 203 concerning its six non-cost-of-service ratemaking objectives: "It is not necessary that in every instance all of the purposes be achieved. It is sufficient if any objective is achieved and none is adversely affected."[22] The Companies' proposed residential Basic Service Charges meet these objectives.

Q. Are the Companies' proposed residential Basic Service Charges consistent with

21 *In the Matter of: General Adjustment of Electric Rates of East Kentucky Power Cooperative, Inc.*, Case No. 2008-00409, Order at 6 (Mar. 31, 2009).
22 *Id.* at 7.

the marginal-cost considerations you quoted above from Administrative Case No. 203?

A. Yes. The marginal-cost-related rate considerations the Commission quoted from PURPA address take into effect how "total costs to an electric utility are likely to change if - (a) additional capacity is added to meet peak demand relative to base demand; and (b) additional kilowatt-hours of electric energy are delivered to electric consumers."[23] In other words, they are demand- and energy-related considerations, not customer-related distribution costs. The basic service charges recover customer-related distribution costs for both Companies and are not based on any transmission, generation, or demand-related distribution costs; those costs are reflected in the proposed residential energy charges. Therefore, the Companies' proposed residential electric Basic Service Charge is fully consistent with the marginal-cost-related considerations the Commission addressed in Administrative Case No. 203.

Proposed Residential Time-of-Day Rates

Q. Do you agree with Mr. Chernick's recommendation that the time-of-day energy rate should be modified to include April and October in the summer period?

A. No. KU and LGE proposed using the same definitions of the summer periods that are used in existing rates that have previously been approved by the Commission (see KU Power Service Tariff, Sheet No. 15, LGE Power Service Tariff, Sheet No. 15). If the Companies changed the definition of the summer periods in the residential time of day

23 *Id.* at 10.

tariffs that they are proposing, for the sake of consistency, they would need to change the definition of the summer periods in their other tariffs, which the Companies are not proposing to do at this time.

Q. Do you agree with Mr. Chernick's recommendation that the winter evening should be included in the winter peak period and the differentials between the peak and off-peak rates should be reduced?

A. No. Mr. Chernick based his recommendation that the winter evening should be included in the winter peak period on the observation that winter months have a secondary peak in the evening that is lower than the morning peak, and his claim that strong price signals that shift load off the morning peak may create a new evening peak.[24] The Companies wanted to keep the winter peak period as narrow as possible and do not believe that there is much opportunity to shift load from the morning peak period to the evening. Mr. Chernick's response regarding loads that could be shifted from the morning peak to the evening peak demonstrates little potential for such a significant shift from morning to evening peak periods.[25] Furthermore, increasing the size of the peak period would make the time of day rate less useful to residential customers and would reduce the magnitude of the financial benefit from shifting load to the off-peak period. Both of these impacts would likely reduce the number of

24 Chernick Direct Testimony, Case No. 2014-00371, 27:10-13 and , Case No. 2014-00372, 27:12 through 28:2

25 Sierra Club response to LGE 3 which states that "The loads that might most commonly be shifted would be laundry (clothes washing and associated water-heating load, clothes drying) and dishwashing (whether by hand or in a dishwasher, including the associated water-heating load). Other loads that might be shifted would include other hot-water uses (e.g., when the floor is washed, or the dog gets its bath), some cooking (e.g., the choice between using a slow cooker all day or a pressure cooker in the evening to make dinner), and specialized uses (e.g., a pottery kiln)."

customers who may want to volunteer to take service under the time of day rate. Mr. Chernick justifies his recommendation to reduce the differential between on-peak and off-peak prices on a concern that “dramatically flattening the rate differentials in the future may disrupt industries (rooftop solar, electric vehicle sales and service) that develop on the basis of the Company’s exaggerated incentives.”[26] When asked whether reducing the differential between on-peak and off-peak energy charges would reduce the financial incentive to shift load to off-peak periods, Mr. Chernick responded in the affirmative but qualified his affirmative response stating:

> Reducing that differential could be beneficial in that offering inappropriately large discounts for using energy outside of the peak pricing period will tend to excessively reward customers who already use energy primarily outside that period or who shift load out of the peak pricing period, excessively penalize customers who shift load into the peak period, and encourage inefficient investments (of capital, time, increased total energy use, effort, inconvenience and discomfort) to shift load, potentially spending much more to shift than the shift would save. (Sierra Club Response to Data Request LGE-5)

Mr. Chernick’s response is premised on the on-peak/off-peak differentials being “inappropriately large discounts.” However, the on-peak/off-peak differentials developed by the Companies are based on the costs of serving in each of these periods as developed from the cost of service study. Mr. Chernick’s concern that the on-peak/off-peak differentials are “inappropriately large discounts” is speculative and is not based on the cost of offering time of day rates using the peak periods that the Companies have proposed. The Companies’ proposed rates are based on the cost of

26 Chernick Direct Testimony, Case No. 2014-00371, 40:23 through 41:3 and Case No. 2014-00372, 41:2-4

offering time of day rates using the peak periods that the Companies have proposed and should be accepted by the Commission.

Q. Do you agree with Mr. Chernick's recommendation that the Commission reject the Company's proposed time of day rate that includes a demand charge?

A. No. The residential time of day rate that includes a demand charge is voluntary and is a more accurate way of recovering the cost of serving a customer than a flat kWh charge. The time of day rate that includes a demand charge would give customers more control over their energy bills than a flat energy charge. With a flat kWh charge, the only way customers can reduce their energy bills is to reduce kWh consumption. With a demand charge, customers can reduce their energy bills by flattening their usage while consuming the same amount of energy, which typically makes them less costly to serve. In the cost of service study, generation and transmission costs are allocated using a base, intermediate and peak allocator, while demand-related distribution costs are allocated using non-coincident peak demand. Non-coincident peak demand is measured by the customer's maximum usage during the month and reflects the fact that utilities must engineer their system by installing equipment of sufficient size to meet a customer's maximum usage. A demand charge is used to reflect the cost of the equipment necessary to meet a customer's maximum usage and provides an incentive for the customer to use the utility's equipment efficiently. Mr. Chernick states that "demand charges do not reflect the variation in marginal energy costs or in market prices."[27] Although Mr. Chernick has identified a couple of the things that demand charges do not cover, he provided no useful information to the Commission about what they do cover. Demand charges are used to recover capacity costs, not energy costs or market prices for electric energy.

With the cost of installing a kW of equipment dwarfing the fuel cost of producing an additional kWh, it is important to both Companies and to customers to provide a price signal and an incentive to conserve capacity and to use the Companies' capacity efficiently. A demand charge provides a price signal and an incentive to conserve capacity and to use the Companies' capacity efficiently. An incentive to conserve energy is provided by the kWh charge which reflects the fuel, scrubber reactant and variable O&M costs of producing an additional kWh. Thus, a rate that includes both a demand charge and an energy charge provides a signal to use both capacity and energy efficiently. If a demand charge is not included in the rate and the fixed cost of the equipment needed to meet a customer's maximum usage is recovered using a kWh charge, there is a strong signal to conserve energy but no incentive to conserve capacity, which is considerably more expensive. Mr. Chernick focuses on sending price signals to conserve energy with no regard for providing incentives to use capacity efficiently. The time of day rate that includes a demand charge accurately reflects the cost of serving customers, and it should be the customers' choice whether they take service under this rate alternative. I see no benefit to customers from taking

27 Chernick Direct Testimony, Case No. 2014-00371, 23:20-21 and Case No. 2014-00372, 23:20-21

this voluntary rate option away from customers and recommend that the Commission ignore Mr. Chernick's recommendation for the Commission to reject the Company's proposed time of day rate that includes a demand charge.

Q. Do you agree with Mr. Chernick that a cost of service study is not designed to estimate the incremental costs of serving an additional kWh on-peak versus off-peak?

A. Yes, but he is inconsistent in how he applies this observation. Mr. Chernick states that "(t)he COSS is not designed to estimate the incremental costs of serving an additional kilowatt-hour on peak versus off-peak."[28] A cost of service study allocates the utility's total cost of serving customers to the various rate classes that the utility serves using allocators based on different cost drivers that reflect various measures of customer usage. However, after recognizing that a cost of service study is not useful for estimating incremental costs, Mr. Chernick uses the cost of service study that I developed to estimate the incremental cost of serving a new customer.[29] The rates developed from a cost of service study reflect the average cost of providing either capacity or energy to customers. Pricing a service using marginal cost typically ignores fixed cost recovery, which is vitally important with the magnitude of fixed costs that are typical in the electric utility industry. Mr. Chernick's discussions of marginal concepts are not useful for the Commission in determining whether the rates proposed

28 Chernick Direct testimony, Case No. 2014-00371, 39:16-18 and Case No. 2014-00372, 39:16-18

29 Chernick Direct testimony, Case No. 2014-00371, 11:18 through 12:7 and Case No. 2014-00372, 11:21 through 12:8

by the Company are just and reasonable, and his recommendations should be ignored by the Commission.

Cost of Service Study Matters

Q. Should the Commission adopt Mr. Baron's suggestion to reject the use of the modified Base-Intermediate-Peak ("BIP") methodology that you used to develop the cost of service studies in this proceeding?[30]

A. No. The use of the modified BIP in developing the cost of service studies in this proceeding is consistent with the Companies' four most recent base-rate cases, and is a methodology the Commission first approved for LG&E in 1990 while rejecting a KIUC-proposed cost-of-service-study alternative.

Q. Do you agree with Mr. Baron's corrections to the cost of service study that you developed in this proceeding?

A. Yes. Mr. Baron pointed out that there should be no allocation of distribution facilities to the RTS class and that metered hourly loads were not adjusted for losses in the development of the demand allocation factors.[31] Both of these changes are consistent with cost of service studies filed in previous rate cases filed by the Company and should be made to the cost of service study that I developed in this proceeding. However, making these changes would not change the Company's proposed rate design that utilizes a uniform percentage increase for each class of customers, which Mr. Baron

30 Baron Testimony at 9-11.
31 Baron Direct Testimony, 5:4-11

supports.[32]

<u>Merging LG&E Electric Rates CTODP and ITODP</u>

Q. Do you agree with Mr. Baron's recommendation not to merge LGE Rates CTODP and ITODP in this proceeding?

A. No. Mr. Baron admits that he does not oppose the merger of LGE Rates ITODP and CTODP conceptually but opposes this merger because it is not consistent with gradualism. In my opinion, this is exactly the right time to merge these two rate classes. With a uniform increase of 2.73% for all LGE rate classes, the impact of merging these two rates at this time is likely to be smaller than it would be in a future rate case where the overall rate increase might be larger. Additionally, merging these two rates would be consistent with the rates that KU offers.

<u>Kentucky School Board Association Matters</u>

Q. Do you agree with Mr. Willhite that recovering the increase allocated to Rates PS-Sec and TODS through increased demand charges violates the principles of gradualism?

A. No. I disagree with Mr. Willhite's statement that recovering the increase allocated to Rates PS-Sec and TODS through increased demand charges violates the principles of gradualism.[33] When gradualism is considered in designing rates, it is typically applied to the overall increase assigned to a rate class and not to the change in individual rate components. The rate increases assigned to Rates PS-Sec and TODS are the same as

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32 Baron Direct Testimony, 20:3-8
33 Willhite Testimony, Case No. 2014-00371, 3:25-30 and Case No. 2014-00372, 3:26-29

the increases assigned to other rate classes and are consistent with the concept of gradualism. KU found that if rates of return on rate base among rate classes were reduced, as Mr. Willhite recommends, the rate increase to some rate classes would be more than 20%, which the Companies believed raised concerns about gradualism. Thus, the Companies' proposed rate design that assigns uniform increases to each rate class is consistent with the concept of gradualism rather than violating the concept of gradualism as Mr. Willhite claims. In fact, reducing the differences in the rates of return among the rate classes as Mr. Willhite suggests is more likely to violate the concept of gradualism than the Companies' proposed rate designs.[34]

Q. Do differences in the energy bills for individual schools served under Rates PS-Sec and TODS from the class average show that the proposed rates are inconsistent with gradualism?

A. No. Mr. Willhite also regards an energy bill increase to some schools being larger than the class average as an indication that the proposed rates are not consistent with the concept of gradualism for both KU and LGE.[35] But Mr. Willhite's claim is another misapplication of the concept of gradualism. By the way they are calculated, rates are averages with some entities receiving an energy bill larger than the class average and some receiving an energy bill below the class average based on the usage patterns of individual customers within the class. If some schools have an energy bill above the class average percentage increase, there are other schools with an energy bill below the

34 Willhite Testimony, Case No. 2014-00371, 10:1-2 and Case No. 2014-00372, 9:45-46
35 Willhite Testimony, Case No. 2014-00371, 10:4-10 and Case No. 2014-00372, 10:1-7

class average percentage increase. These differences are a result of energy usage patterns that deviate from the class average and are an indication that different usage levels and patterns result in different costs being incurred by the Companies and not an indication of the rate increases to Rates PS-Sec and TODS being inconsistent with the concept of gradualism as Mr. Willhite claims. For both Companies, the rate increases for Rates PS-Sec and TODS are the same as the rate increases for the Companies' other rate classes, which is consistent with the concept of gradualism.

Q. Do you agree with Mr. Willhite that recovering the increase allocated to Rates PS-Sec and TODS through increased demand charges is contradictory to sound cost of service principles?

A. No. I disagree with Mr. Willhite's statement that recovering the increase allocated to Rates PS-Sec and TODS through increased demand charges is contradictory to sound cost of service principles.[36] The costs that the Companies propose to recover using demand charges are demand-related fixed generation, transmission and distribution costs that were allocated to Rates PS-Sec and TODS. Recovering these demand related costs using demand charges is totally consistent with the sound ratemaking principle of recovering fixed costs through fixed charges and variable costs through variable charges. In fact, recovering these demand-related fixed costs through an energy charge as Mr. Willhite suggests would violate this ratemaking principle by recovering a fixed cost using a variable charge assessed on a kWh basis.

36 Willhite Testimony, Case No. 2014-00371, 3:27-30 and Case No. 2014-00372, 3:26-29

Q. Do you agree with Mr. Willhite that the schools served under Rates PS-Sec and TODS are subject to an unreasonable disadvantage?

A. No. Mr. Willhite claims that the schools served under Rates PS-Sec and TODS are subject to an unreasonable disadvantage because they have different load characteristics than industrial and commercial customers served on those rates.[37] Mr. Willhite bases this conclusion on a comparison of load shapes for schools, commercial customers and industrial customers for the months of July and August in Exhibits RLW-2 and RLW-3. He does not examine the relative load shapes for the months of December, January and February when the Companies typically experience winter peaks and when Mr. Willhite admits that the load shape for schools is likely to be coincident with the Companies' winter system peaks.[38] He also does not examine the relative load shapes for the shoulder months of September, October, November, March, April and May. Although the summer peak is used for planning system resources, the Companies have experienced annual peaks during the winter months several times since the year 2000, and it is necessary to consider the impact of Rates PS-Sec and TODS in the winter months, when school load shapes are likely to coincide with the Companies' system peaks, and during the shoulder months to determine whether the proposed rates are unreasonable. Mr. Willhite's analysis is very selective and only examines the load shapes in two months. Furthermore, Mr. Willhite admits that schools

37 Willhite Testimony, Case No. 2014-00371, 10:43 through 11:8 and Case No. 2014-00372, 10:38 through 11:3
38 Willhite Testimony, Case No. 2014-00371, 10:35-36 and Case No. 2014-00372, 10:29-30

typically have lower load factors than other customers served in these rate classes, which typically makes them more expensive to serve because the resources installed to serve them are used on a more sporadic basis.[39] He has not demonstrated that the proposed rates are unreasonable when applied to entities taking service under Rates PS-Sec and TODS for an entire year.

Q. Did Mr. Willhite support his recommendation that separate rate classes for schools be added and that the demand charges for these rates be set at some percentage of the demand components for Rates PS-Sec and TODS?

A. Mr. Willhite recommends that the Company be directed to add Rates PS-School and TOD-School to its tariff and that the demand charges be set at no greater than 75% of the PS and TODS demand charges for KU and no greater than 85% of the PS and TODS demand charges for LGE.[40] As noted above, Mr. Willhite's recommendation to establish separate rate classes for schools is based on a very selective analysis of load shapes in only two months. Even for his analysis of the two months included in Exhibits RLW-2 and RLW-3, he has not shown that the load shapes for schools deviate from the class average by an amount that would justify the formation of separate rate classes for schools. Additionally, there is no evidentiary support for Mr. Willhite's recommendation that the demand charges for schools be set at no more than 75% of the demand components for Rates PS and TODS for KU and 85% of the demand

39 KSBA Response to LGE 5d which states that "Mr. Willhite has observed that annual school load factors range from 25 to 45 percent with elementary schools at the lower end of the range and high schools at the higher end. Non-school loads such as industries and businesses typically have much higher load factors."
40 Willhite Testimony, Case No. 2014-00371, 11:13-15 and Case No. 2014-00372, 11:4-9

components for Rates PS and TODS for LGE. Lacking evidentiary support, Mr. Willhite's recommendation to establish separate rate classes for schools should be disregarded by the Commission. Even if the Commission were to order the formation of separate rate classes for schools, Mr. Willhite's recommendation on the appropriate level of the demand charge totally lacks evidentiary support and could not be used by the Commission in establishing rates for these new rate classes.

Q. Do you agree with Mr. Willhite's recommendation to unfreeze Rate AES?

A. No. Mr. Willhite recommends that the Commission unfreeze Rate AES for KU and order LGE to develop a Rate AES for schools.[41] Rate AES does not contain a demand charge component, without which it is not possible to accurately charge for the demand-related fixed generation, transmission and distribution costs that service to schools with differing load characteristics impose on KU. As noted earlier, a demand charge component is the most accurate method of charging for these demand-related costs and requiring schools to take service under Rates PS and TOD would help to correct this problem. Mr. Willhite's recommendation to unfreeze Rate AES for KU and to order LGE to develop a Rate AES is inconsistent with his recommendation to add Rates PS-School and TOD-School that contain demand rates, as this recommendation recognizes the importance of demand charges in accurately billing schools.[42] Mr. Willhite's statement that the lack of a demand charge in Rate AES "simply means there is intra-class cross-subsidization among the school accounts" does not provide the

41 Willhite Testimony, Case No. 2014-00371, 12: 24-27 and Case No. 2014-00372, 11:43-46
42 Willhite Testimony, Case No. 2014-00371, 12: 40-46

Commission with sufficient justification to adopt Mr. Willhite's recommendation to unfreeze rate AES for KU and to order LGE to develop a Rate AES.[43]

Q. Do you agree with Mr. Willhite's recommendation regarding sport field lighting?

A. No. Mr. Willhite recommends that sports fields be billed under a rate that contains only an energy charge with no demand charge. Because they have a low load factor and their usage is sporadic, it is difficult, if not impossible, to recover the significant demand-related generation, transmission and distribution costs associated with serving sports fields using only an energy charge with no demand charge. The use of a demand charge in billing these loads makes it possible to recover the significant demand-related generation, transmission and distribution costs associated with serving sports fields so that these costs are not shifted to other customers for recovery. The magnitude of the increase for sports field lighting energy bills provided by Mr. Willhite gives some indication of the subsidy that these loads were receiving when being billed on an energy-only basis.[44] Rather than indicating a problem of being unreasonably treated when billed using a demand charge, the 400% to 500% increases that Mr. Willhite cited show just how much demand charges are needed in billing these loads and indicate the magnitude of the subsidy that they have been receiving from other customers when billed using an energy-only rate. Mr. Willhite has not provided cost support for his recommendation that sports fields be billed using an energy-only rate. Lacking evidentiary support, there is no basis for the Commission to order the development of

43 Willhite Testimony, Case No. 2014-00371, 12: 34-36
44 Willhite Testimony, Case No. 2014-00371, 13: 12-13

a sport field rate rider as recommended by Mr. Willhite.

Revenue Allocation

Q. Do you agree with the proposal to reduce subsidies among classes that Mr. Chriss suggests?

A. My interpretation of the proposal described in Mr. Chriss' Direct Testimony regarding the KU rate design is to use any reduction in the revenue requirement to reduce the subsidies among the Company's customer classes.[45] With regard to the rate design proposed by KU, Mr. Chriss stated that he does not oppose the Company's proposed rate design at the level of the Company's proposed revenue requirement.[46] However, he suggests using any reduction in the revenue requirement proposed by the Company to reduce subsidies among classes while capping the increase to any rate class for KU at 9.6%. The use of any reduction in the revenue requirement to reduce subsidies among classes while capping the increase to any rate class at 9.6% for KU is acceptable to the Company as it would avoid significant increases to any single rate class. However, the methodology that Mr. Chriss suggests for accomplishing this is not clear, particularly the first two steps.[47] The first step could be interpreted several ways. First, it could mean that 25% of any revenue reduction would be allocated to reducing the subsidies among rate classes, but then it is not clear how this would be allocated "to the revenue requirement for each rate class."[48] Would some of the reduction be allocated to classes

45 Chriss Direct testimony, Case No. 2014-00371, 14:6 through 18:7
46 Chriss Direct testimony, Case No. 2014-00371, 14:6-8
47 Chriss Direct testimony, Case No. 2014-00371, 17:17 through 18:7
48 Chriss Direct testimony, Case No. 2014-00371, 17: 20-22

that were already receiving a subsidy, which step 2 seems to imply, or to only those classes that were below the average rate of return for all rate classes? Mr. Chriss' proposed methodology is confusing and requires the exercise of discretion by the Commission. The Company agrees with use of any reduction in the Company's revenue requirement to reduce subsidies among classes while capping the increase to any rate class at 9.6%, but takes no position on how this is accomplished. Because it does not understand the methodology that Mr. Chriss is proposing, the Company does not support Mr. Chriss' proposed methodology.

With regard to the rate design proposed by LGE, Mr. Chriss recommended that any increase in revenue requirements be allocated among classes in a way that would reduce the differences in rates of return among customer classes.[49] Mr. Chriss' proposed methodology is confusing and requires the exercise of discretion by the Commission. Because it does not understand the methodology that Mr. Chriss is proposing, the Company does not support Mr. Chriss' proposed methodology.

Rate CTAC Pole-Attachment Charges

Q. Did KU and LGE propose any changes to its cable television attachment charges in these proceedings?

A. No. Neither KU nor LGE proposed changes to their cable television attachment charges in these rate case proceedings. KU and LGE provided evidence in Case Nos. 2012-00221

49 Chriss Direct testimony, Case No. 2014-00372, 15:4-16

and 2012-00222 to support the cable television attachment charges. After an evidentiary hearing considering a settlement agreement, the Companies' cable television attachment charges were found to be fair, just and reasonable and approved by the Commission in an order dated December 20, 2012. In direct testimony filed by Ms. Kravtin in these proceedings, the KCTA has proposed new cable television attachment charges. Therefore, the burden of proof falls on the KCTA to demonstrate that its proposed attachment charges in this proceeding are fair, just and reasonable and that the charges approved by the Commission in Case Nos. 2012-00221 and 2012-00222 are not fair, just and reasonable.

Q. Has the KCTA met its burden of proof by demonstrating that its proposed cable television attachment charges are fair, just and reasonable?

A. No. The cost support submitted by Ms. Kravtin contains numerous errors and aggressively removes costs that should be included in the Companies' cable television attachment charges. In fact, there are mistakes in almost every part of her carrying charge calculations. In addition to all of the errors in her calculations, Ms. Kravtin disregards the fact that KU and LGE filed proposed rates based on a fully-forecasted test year in these proceedings. ***All*** of the rates and charges proposed by KU and LGE in these proceedings are based on forecasted costs. Ms. Kravtin completely ignored the Companies' forecasted rate filing and used historical costs to develop her proposed rates, even though she had an opportunity in discovery to obtain the forecasted data that she would have needed. This forecasted data necessary to calculate attachment charges was not filed with the other cost of service and rate design material because the Companies proposed no changes to attachment charges in these proceedings. Because Ms. Kravtin's calculations are based on historic rather than forecasted data, her proposed rates would be fundamentally inconsistent with all other rates determined in these proceedings. Thus, the cable television attachment charges proposed by KCTA should be disregarded and the Companies' current cable television attachment charges, as approved by the Commission in Case Nos. 2012-00221 and 2012-00222, should be allowed to remain in effect.

Q. Despite the fact that KU and LGE filed fully forecasted rate cases, can the reasonableness of the current rates be supported by current cost data?

A. Yes. Although KU and LGE did not propose changes to their cable television charges in these proceedings, the reasonableness of the rate can be confirmed by updating the carrying charge calculations used to support the pole attachment charges found reasonable by the Commission in the Companies' last rate case proceedings. In Rebuttal Exhibits MJB- 1 and MJB- 2, I have calculated the pole attachment charges using historical cost data for KU and LGE for the 12 months ended October 31, 2014. In these exhibits, the pole attachment charges are calculated using the same methodology used by KU and LGE to support its current cable television rates that were found fair, just and reasonable by the Commission in the Companies' last rate cases. Table 1 compares the current charges to the cost-based charges using current data for KU and LGE as calculated in Rebuttal Exhibits MJB- 1 and MJB- 2:

Table 1		
Company	Current Charges	Charges Updated for Current Cost Data
Kentucky Utilities	$ 9.69	$ 10.58
Louisville Gas and Electric	$ 9.11	$ 11.08

As can be seen from this table, the charges updated for current cost data would be higher than the current charges. As noted earlier, KU and LGE filed a forecasted test year in these proceedings. The above charges are based on historical costs for the 12 months period ended October 31, 2014, and charges based on forecasted costs would likely be higher.

Q. Do you agree with the regulatory principles that Ms. Kravtin claims should guide pole attachment regulation?

A. No. In her direct testimony, Ms. Kravtin makes the following statement:

> The primary purpose of pole rate regulation historically has been, and continues to be, about protecting cable operators and other third-party attachers against monopoly abuses of pole-owning utilities. (Case No. 2014-00371, Direct Testimony of Patricia D. Kravtin, p. 9 and Case No. 2014-00372, p. 10.)

Frankly, as a former regulator I am concerned about the suggestion that the "primary purpose" of pole attachment regulation is to look out for the interests of cable television companies and other attachers over and above the interests of a utility's other ratepayers.

The Commission should be wary of any recommendations that are based on this stated goal. The purpose of rate regulation, including the regulation of pole attachment charges, is to develop fair, just and reasonable charges for all customers taking service from the utility. By developing fair, just and reasonable rates, regulatory commissions balance the interests of ***all*** ratepayers and the utility, not just protecting the interests of cable television companies.

Q. Will lower cable television attachment charges result in lower revenue requirements to KU and LGE in these proceedings?

A. No. KU and LGE are not enriched by cable television attachments charges, regardless of the level at which these charges are set. Any reduction in cable television revenues through the determination of lower pole attachment rates will only serve to increase the rates to other customers. If the Commission determines that lower rates are warranted, then miscellaneous revenues in these proceedings will be reduced and any deficiency created by such reduction will simply be collected from other customers. This underscores the fact that KU and LGE's only objective here is to allocate the revenue increase in these proceedings in such a way that the resultant charges are fair, just and reasonable to all customers.

Q. What errors were made in the calculation of the attachment charges proposed by Ms. Kravtin?

A. Although her calculations are riddled with mistakes, she has made a serious mathematical error in her carrying charge calculations that significantly understates the annual cost for pole attachments. Specifically, contrary to standard ratemaking practice, Ms. Kravtin uses a return on net plant investment in conjunction with a sinking fund depreciation factor. Ms. Kravtin's approach is not only nonstandard, it is also fundamentally flawed.

Q. Net plant is used to calculate both rate base and revenue requirements in a rate case proceeding. Why is the use sinking fund depreciation in conjunction with a rate of return on net plant investment incorrect?

A. In a rate case, the component of the revenue requirement for recovering the return on investment is determined by applying a rate of return to net plant investment, and straight-line depreciation is used to determine the depreciation component of the revenue requirement, not sinking fund depreciation. Using sinking fund depreciation in conjunction with a rate of return on net investment significantly understates the appropriate level of revenue requirements.

It is a fundamental principle in calculating carrying charges, a subject that frequently arises in proceedings before the Federal Energy Regulatory Commission ("FERC"), that either (1) ***straight-line depreciation*** can be used in conjunction with a rate of return on ***net plant investment***, or (2) ***sinking fund depreciation*** can be used in conjunction with ***gross plant investment***. The FERC will allow either approach, as long as the utility doesn't switch back and forth between the two methodologies. Ms. Kravtin has cobbled together a nonstandard and inconsistent approach that uses the elements from these two accepted methodologies in order to produce a lower charge for pole attachments. Specifically, her approach combines **sinking fund depreciation** with a return on **net plant investment**. By combining sinking fund depreciation with net plant investment, she has chosen the lower of the two depreciation measures in combination with the lower of the two measures of return on investment.

Q. What's wrong with using a sinking fund factor with net plant?

A. Using a sinking fund factor in conjunction with calculating the return on the basis of net plant violates the principle of ***economic equivalency***.

Q. What is economic equivalency?

A. Calculations in finance and engineering economics are grounded on the principle that two or more cash flows, revenue requirements, financial alternatives, etc. can be placed on an equivalent basis for comparison by properly considering the effect of the time value of money. The principle of economic equivalency is what allows a bank to loan someone money to purchase a home in exchange for a payment stream from the borrower over the life of the mortgage. Loan payments, annuities, and carrying charge calculations are based on the principle of economic equivalency that permits a future series of payments to be considered equivalent to a present value amount by using a consistent discount rate. A fundamental aspect of economic equivalency is that if two or more payment streams are being evaluated, the same discount rate must be used in the evaluation of each stream. The concept of economic equivalency is discussed in practically every economic engineering or finance textbook. For example, see H.G. Thuesen, W.J. Fabrychy, and G. J. Thuesen, *Engineering Economy*, Fifth Edition, Chapter 5 and Chan S. Park, *Contemporary Engineering Economics*, Chapter 3. In the second text, Park writes:

> The equivalence between two cash flows is a function of the magnitude and timing of individual cash flows and the interest rate or rates that operate on those cash flows. This principle is easy to grasp in relation to

> our simple example: $1,000 received now is equivalent to $1,762.34 received five years from now only at a 12% interest rate. *Any change in the interest rate will destroy the equivalence between the two sums*, as we will demonstrate in Example 3.5. (Id. at p. 68. Emphasis supplied.)

This makes it clear that economic equivalency cannot be established unless consistent discount rates are used in the analysis.

Q. Please explain what you mean by a discount rate.

A. A discount rate is the rate used to calculate present value or future value factors in economic studies and comparisons. The discount rate represents a company's opportunity cost or weighted cost of capital. It is therefore the rate used in present or future value calculations that allows a payment received or an outlay made at one point in time to be compared on a consistent basis to a payment or outlay at another point in time. Thus, by using a consistent discount rate reflecting a company's opportunity cost, one series of payments can be compared to another series of payments on a present value basis. If the present values of two different payment streams are calculated using different discount rates, then fundamentally they are not equivalent. In evaluating two or more payment streams, it is necessary to use the same discount rates in calculating the present value of the payment streams.

Q. Can you provide simple examples demonstrating the concept of *economic equivalency*?

A. Yes. Suppose that a present value of a lump-sum amount is $1,000. It can be demonstrated that this present-value lump-sum amount is equivalent to the following two five-year payment streams using a 10% discount rate (rate of return): (1) an annual payment amount determined by applying the rate of return to net investment and then adding straight-line depreciation, and (2) an annual payment amount determined by applying the rate of return to gross investment but then adding sinking fund depreciation.

The mathematical and economic equivalency of these two payment streams can be seen from the following tables. Table 2 shows the present value of payment stream by calculating the annual payments based on the return on net investment plus straight line depreciation.

Table 2

Year	Gross Investment	Straight Line Depreciation	Net Investment	Return @10%	Payment Amount	Present Value @10%
1	$ 1,000	$ 200	$ 1,000	$ 100	$ 300	$ 273
2	1,000	200	800	80	280	231
3	1,000	200	600	60	260	195
4	1,000	200	400	40	240	164
5	1,000	200	200	20	220	137
						$ 1,000

As can be seen from Table 2, when using a 10% discount rate, the sum of the present value annual payments is mathematically equal to the original $1,000 investment. Consequently, this payment stream calculated using straight line depreciation and return on net investment is economically equivalent to the $1,000 original cost investment.

Table 3 shows the present value of the payment stream by calculating the annual payments based on the return on gross investment plus sinking fund depreciation.

Table 3					
		Sinking			Present
	Gross	Fund	Return	Payment	Value
Year	Investment	Depreciation	@10%	Amount	@10%
1	$ 1,000	$ 164	$ 100	$ 264	$ 240
2	1,000	164	100	264	218
3	1,000	164	100	264	198
4	1,000	164	100	264	180
5	1,000	164	100	264	164
					$ 1,000

As can be seen from Table 3, when using a 10% discount rate, the sum of the present value annual payments is mathematically equal to the original $1,000 investment. When using sinking fund depreciation in conjunction with return on gross investment, the resulting payment stream is economically equivalent to the $1,000 original cost investment. Therefore, the present value of a stream of annual payments calculated using a 10% rate of return on net investment plus straight-line depreciation is mathematically and economically equivalent to a stream of annual payments calculated using a 10% rate of return on gross investment plus sinking-fund depreciation.

Economic equivalency is the principle that makes it possible to compare the present value amount to a stream of payments. It should be emphasized that the same discount rate of 10% must be used in both present value calculations or the premise on which economic equivalency is based is violated. Using a different discount rate in the evaluation of the payment streams violates the premise on which economic equivalency is based.

Obviously, it would be possible to force the present value of practically any two payment streams to be equal by using different discount rates, but using different discount rates would not demonstrate that the two payment streams were economically equivalent. If different discount rates are used then *fundamentally* the payment streams cannot be considered equivalent. Rebuttal Exhibit MJB-3 provides an example of how Ms. Kravtin uses different discount rates to force her revenue requirement streams to be equal, which, of course, means that her calculations and conclusions are not economically equivalent and thus meaningless.

Q. How do Ms. Kravtin's carrying charge calculations violate *economic equivalency*?

A. She inappropriately uses sinking fund depreciation in conjunction with a return calculated by applying the rate of return to net investment. In the example in Table 1 above, the 10% rate of return was applied to net investment, but straight-line depreciation was used to determine the annual payments. Consequently, the present value of the payment stream is equal $1,000. In the example in Table 2, the 10% rate of return was applied to gross investment, but sinking fund depreciation was used to determine the annual payments. In both cases, the present value of the payment stream is equal to $1,000. In Ms. Kravtin's analysis, she calculates the return using net plant but inappropriately uses sinking fund depreciation, which mathematically violates economic equivalency and which violates the sound regulatory principles that are applied consistently by FERC.

Q. Can you provide a simple example showing how Ms. Kravtin's approach is mathematically incorrect?

A. Yes. Table 4 shows the effect of using net plant to calculate the return in conjunction with sinking fund depreciation.

Table 4						
		Sinking				Present
	Gross	Fund	Net	Return	Payment	Value
Year	Investment	Depreciation	Investment	@10%	Amount	@10%
1	$ 1,000	$ 164	$ 1,000	$ 100	$ 264	$ 240
2	1,000	164	800	80	244	201
3	1,000	164	600	60	224	168
4	1,000	164	400	40	204	139
5	1,000	164	200	20	184	114
						$ 863

As can be seen from Table 4, calculating carrying costs on the basis of sinking fund depreciation plus return on net investment results in a sum of present value payments of only $863. This approach does not provide for full recovery of the $1,000 original investment, and the use of this methodology by Ms. Kravtin understates the cost of and the rate that should be charged for a pole attachment.

Q. Can you demonstrate how the payment stream shown in Table 4 can be forced to produce a present value of $1,000 by forcibly manipulating the discount rate?

A. Yes. If the cost of money is 10%, then obviously the discount rate should also be 10%, but a lower discount rate can be found through the application of goal seeking tools or by other means that will artificially increase the present value of the stream of payments to equal $1,000. As can be seen from the Table 5, using a discount rate of 4.1 % instead of the 10% rate of return will produce a sum of present value payments of $1,000. Of course, the comparison is meaningless because a 4.1% discount rate was used instead of the 10% discount rate corresponding to the actual cost of money in the example. Rebuttal Exhibit MJB-3 provides an example of how Ms. Kravtin has used a different, lower discount rate to create a false impression that the use of sinking fund depreciation in conjunction with return on net plant investment is acceptable.

Table 5						
		Sinking				Present
	Gross	Fund	Net	Return	Payment	Value
Year	Investment	Depreciation	Investment	@10%	Amount	@4.1%
1	$ 1,000	$ 164	$ 1,000	$ 100	$ 264	$ 253
2	1,000	164	800	80	244	225
3	1,000	164	600	60	224	198
4	1,000	164	400	40	204	173
5	1,000	164	200	20	184	150
						$ 1,000

.

The inappropriate use of sinking fund depreciation with a return on net investment means that only a 4.1% return is actually provided by the payment stream in the example above rather than the intended rate of return of 10%.

Q. In calculating her proposed rates, where specifically does Ms. Kravtin use sinking fund depreciation in conjunction with a return on net investment?

A. Ms. Kravtin calculates her proposed attachment charges in Attachment 2 of her testimony. In the first page of her analysis (in the middle of the page) it can be seen that she uses a sinking fund depreciation factor of 1.36% for the test year calculations for KU and of

1.37% for the test year calculations for LGE, but on the same page it can be seen that she makes an adjustment to the rate of return from 7.23% to 3.10% for KU and from 7.31% to 3.95% for LGE which reflect a return on net investment, rather than the appropriate return on gross investment that is consistent with the use of sinking fund depreciation.

Q. In Attachment 3 to her direct testimony, Ms. Kravtin purports to demonstrate that her methodology is equivalent to a non-levelized approach using straight line depreciation and a return on net investment. Does her analysis truly demonstrate that the two approaches are equivalent?

A. No. Ms. Kravtin's analysis is incorrect and is based on the use of two different discount rates. Rebuttal Exhibit MJB-3 is a markup of Ms. Kravtin's Table 1 illustrating her use of a discount rate of 8.32% in the portion of the table analyzing "Non-Levelized" carrying charge calculation and use of a discount rate of only 4.16% in the portion of the table analyzing her "Levelized" carrying charge calculation. Because she used *sinking fund depreciation* in conjunction with a rate of return on *net investment*, it was necessary for her to use a lower discount rate to force the present value for her "Levelized" carrying charges to equal the "Non-Levelized" carrying charges. Specifically, Ms. Kravtin used a lower discount rate to force the present value payments to equal $1,000. However, Ms. Kravtin attempts to obscure the fact that she used a 4.16% discount rate by referring to it as a "Present Value @Gross ROR" instead of labeling is "Present Value@4.16%" as she did with the "Present Value@8.32%" in her analysis of "Non-Levelized" carrying charges (see Rebuttal Exhibit MJB- 3). Despite Ms. Kravtin's attempts at obfuscation, her analysis demonstrates that her proposed carrying charges would only provide a 4.16% return.

By providing a low rate of return for cable television pole attachment service, her charges would shift costs to other ratepayers. Specifically, by requiring cable television companies to provide a return of only 4.16%, she would force other customers to pick up the difference between the 8.32% rate of return that should be provided by cable television customers and the 4.16% they would actually provide under Ms. Kravtin's rates.

Q. What happens to her analysis if a consistent discount rate is used?

A. In Rebuttal Exhibit MJB-4, I have corrected the error made in Table 1 of Attachment 3 to Ms. Kravtin's KU and LGE testimony. As can be seen from Rebuttal Exhibit MJB-4, Ms. Kravtin's mathematically flawed carrying charge calculation, which inappropriately uses sinking fund depreciation in conjunction with a rate of return on net plant, results in a sum of present value of annual carrying charges of only $617.89 which is equivalent to only 61.80% of total costs. This suggests that Ms. Kravtin's flawed carrying charge approach would understate the actual cost of pole attachment service by 38.20% for both KU and LGE.

Q. Does your analysis demonstrate that Ms. Kravtin's proposed cable television attachment charges are significantly understated?

A. Yes.

Q. Do you agree with the way that Ms. Kravtin calculated the O&M factor in her carrying charge calculation?

A. No. Ms. Kravtin calculates the O&M factor by dividing pole-related operation and maintenance expenses by Account 364 – Poles, Account 365 – Conductors and Devices ("Conductors"), and Account 369 Services ("Services"). Ms. Kravtin specifically mentions tree-trimming expenses as an expenses item that should be spread to Conductors and Services. While it is true that tree trimming protects conductors as well as poles, she fails to consider that KU and LGE's tree-trimming efforts also help protect the lines owned by cable television companies. In calculating the carrying charges for pole attachment service, it is not possible to spread a portion of tree-trimming expenses to the cable television companies' distribution lines because their property is not included on KU and LGE's books. The only way to allocate the cost of tree-trimming to lines owned by cable television companies is to spread the costs to poles. Cable television companies are billed for attachment service solely on the basis of a pole attachment. If tree-trimming and other expenses are allocated to Conductors and Poles, as suggested by Ms. Kravtin, then the cable television companies would have to be billed for tree trimming services based on the miles of cable television line running along LGE and KU's rights of way, which is not a practical approach. The cable television charge is unitized on the basis of a pole attachment charge; therefore, the charge should include a proportionate share of tree trimming expenses which cannot be billed to the miles of cable television lines and services which KU and LGE's tree trimming activities also benefit.

Q. Do cable television companies perform any tree trimming on their own lines?

A. Not that the Companies are aware of, and definitely not in any systematic or regular manner. As far as the Companies know, the cable television companies rely exclusively on KU and LGE to provide tree trimming.

Q. Does KU or LGE perform routine tree trimming on services?

A. No. KU and LGE rarely perform tree trimming on services. Tree trimming is focused on overhead lines and not services which are located on customers' property. The fact that Ms. Kravtin fully spreads tree-trimming to Account 369 Services is another flaw in her analysis.

Q. Are there other errors in her calculations?

A. Yes, there are several others. Ms. Kravtin's carrying charge calculation for LGE uses the wrong rate of return. As shown on the second page the carrying charge calculations in Attachment 2 of her testimony, the weighted return on capital that she uses is 7.31%. The weighted rate of return should be 7.36% percent, as shown in Schedule J-1, page 2 of the filing requirements for LGE.

Q. Did Ms. Kravtin use the correct income tax rate in her carrying charge calculations?

A. No. As shown the second page of the carrying charge calculations in Attachment 2 of her testimony, Ms. Kravtin uses a composite state and federal income tax rate of 36.86% for KU and 37.52% for LGE. The composite state and federal income tax rate should be 38.90%, for both Companies as shown in the responses to Question 11 of the KCTA's First Data Requests to KU and LGE. The income tax rates used by Ms. Kravtin incorrectly include Section 199 deductions for KU and LGE. The Section 199 deduction is a tax break for businesses that perform domestic manufacturing and certain other production activities. Because electric distribution poles and pole attachments are not involved in manufacturing or production, Section 199 deductions should not be reflected in the income tax rates. Therefore, in calculating carrying charges for the cable television attachment charges, the statutory state and federal income tax rate of 38.90% must be used.

Q. Did Ms. Kravtin use the correct property tax rate in her carrying charge calculations?

A. No. Ms. Kravtin used an incorrect property tax percentage in her carrying charge calculations. Specifically, she used an effective property tax rate of 0.22% for both KU and LGE. The property tax rate should be 0.42% for KU and 1.10% for LGE, as calculated against gross plant. The rates should be 0.76% for KU and 2.03% for LGE if net plant is used instead, as proposed by Ms. Kravtin; however this would necessitate the use of straight line depreciation rather than the sinking fund depreciation that Ms. Kravtin uses in her analysis. The data necessary to calculate the effective property rates were provided in KU and LGE's responses to Question 25 to KCTA's Supplemental Data Requests.

Q. Did Ms. Kravtin use the correct amount for LGE's tree trimming expenses?

A. No Ms. Kravtin used $16,450,212 for tree trimming expenses. The amount should be $16,088,333. Of all the mistakes in Ms. Kravtin's attachment charge calculation, this is the only one that doesn't work in her client's favor.

Q. Are there problems with the labor costs used in Ms. Kravtin's carrying charge calculations?

A. Yes. She estimates labor expenses used in the calculation simply by prorating costs from the Company's previous CATV calculations. The labor expenses shown on the second page of Attachment 2 to her testimony for Accounts 593001 and 593004 simply reflect pro-rated amounts based on the amounts shown in the Companies carrying charge calculations submitted in Case Nos. 2012-00221 and 2012-00222. Ms. Kravtin seems to have made no attempt to use actual expenses.

Q. Ms. Kravtin also proposed to reduce costs for "minor appurtenances". Do you agree with this adjustment?

A. No. Ms. Kravtin proposed to adjust pole costs by 15% to eliminate "minor appurtenances." KU and LGE have no cost classification on its books for "minor appurtenances," and they do not track the types of items that Ms. Kravtin claims should be included in this cost category. In prior rate cases for both Companies, no reduction for "minor appurtenances" was used in calculating rates for cable attachments. Administrative case No. 251 is a simplified method for calculating a charge for cable attachments that does not fully allocate all of the Companies' costs, as is done in a cost of service study. Because major cost items do not enter the calculation of the charge for cable attachments, as explained more fully below, the Companies did not make a reduction for minor appurtenances considering this to be at least a wash with the other costs that were not included.

Q. Is it clear from the Commission's Order in Administrative Case No. 251 that 15% should be excluded to reflect "minor appurtenances"?

A. No. The Commission Order in Administrative Case No. 251 dated September 17, 1983, seems to suggest that 15% should be excluded from the cost of poles when Account 364 is somehow used in aggregate. Specifically, the Commission stated that "an adjustment of 15 percent subtracted from the sum of the appropriate sub-account of FERC Form 1, Account 364, and a deduction of $12.50 per ground, when such grounds are included in Account 364, will reasonable approximate the cost of an average bare wooden electric pole." The Commission Order seems to contemplate removing 15% from the total of Account 364, but in the calculation of the Companies' pole attachment charges, Account 364 is never used in total. Instead, LGE/KU used only the bare pole costs for the pole sizes specified by the Commission to be used to calculate two and three party pole attachment costs. Because the Companies did not propose to change the charge for cable attachments in this proceeding and the charge for cable attachments only became an issue when intervenor testimony was filed, the Companies have not had a reason to fully develop the supporting data for use in this rate proceeding.

Q. Do you have concerns about arbitrarily reducing pole costs by 15% for "minor appurtenances"?

A. Yes. The carrying cost calculation for the pole attachment charge is a simple calculation that does not account for a large number of costs that should be allocated to pole attachment service. KU and LGE's other rates are determined on the basis of fully-allocated cost of service. This has not been the case for cable television attachment charges which have been calculated using the simplified procedure identified in Administrative case No. 251. By using a simple formula rate to determine the charges, cable television attachment service has not received an allocation of a large number of common costs that would have been allocated to cable television attachment service if cable television attachment service had been included as a class in the Companies' cost of service studies. In a cost of service study, all of the Companies' common costs are fully distributed and assigned to each class of customers. By using a simple formula-rate calculation, as is done with the pole attachment charge, some legitimate common costs are not fully assigned to the cable television attachment charge. It would not be appropriate to make an arbitrary and unsupported adjustment for "minor appurtenances" without considering other costs that would properly be allocated to cable television customers in a fully allocated cost of service study.

Q. Can you provide examples of costs that would be allocated to cable television operators in fully allocated cost of service study that are not considered in the Companies' cable television charge?

A. Yes. In the Companies' cost of service studies, there are many cost items that are allocated to all customers classes on a fully-distributed basis that are not considered in the development of the cable television attachment charges. For example, expenses related to distribution supervision and engineering are recorded in Accounts 580 and 590. Supervision and engineering activities relate to poles as they do with conductors, transformers and other distribution facilities. Supervisors and engineers are routinely involved in the planning, design, scheduling, and oversight of operations and maintenance of poles. Even though it would be appropriate to assign a portion of distribution supervision and engineering expenses to poles in the determination of the cable television attachment charge, these expenses have not been traditionally included in the simple rate formula for calculating cable television attachment charges developed in Administrative Case No. 251. However, these costs are included in the determination of rates for KU and LGE's service to other rate classes. Likewise mapping expenses, distribution rental charges, miscellaneous expenses, customer records, and miscellaneous customer expenses are involved in providing service to pole attachments just as they are jointly related to providing service to other types of customers. The following operation and maintenance expenses are fully allocated to pole facilities in a cost of service study but are not assigned or otherwise captured in the calculation of the cable television attachment charge specified in Administrative Case No. 251:

Table 6

Operation and Maintenance Expenses Which are not currently included in Cable Television Attachment Charge

Account Number	Description
580	Distribution Operations Supervision & Engineering
588	Miscellaneous Distribution Expenses
589	Distribution Rents
590	Distribution Maintenance Supervision & Engineering Expenses
598	Miscellaneous Distribution Maintenance Expenses
903	Customer Records
905	Miscellaneous Customer Expenses

These operation and maintenance expenses are joint costs that are functionally assigned to all distribution functional groups in a cost of service study and allocated to all customers taking distribution service from KU or LGE. It would be inappropriate to include an arbitrary percentage for “minor appurtenances in these proceedings but ignore these other, more significant operation and maintenance expenses. Similarly, the pole attachment charge calculation also ignores a number of net cost rate base items that are fully distributed to all customer classes in a cost of service study. For example, the costs recorded as general plant include the cost of KU and LGE’s central office buildings. These costs are essential in running the business. Therefore it would be appropriate that these costs be allocated to cable television attachment service just as they are assigned to the Companies’ standard electric and gas services. Again, the simple rate formula used to calculate the cable television attachment charge has traditionally ignored these very real and legitimate costs. Likewise, cash working capital, materials and supplies, prepayments, plant held for future use, are just as necessary in providing service to pole attachments as they are for other customers. Pole-related costs are also included in Construction Work in Progress.

The following rate base items are fully allocated to pole facilities in a cost of service study but are not assigned or captured in the calculation of the cable television attachment charge specified in Administrative Case No. 251:

Table 7 Rate Base Components Which are not currently included in Cable Television Attachment Charge
General Plant
Plant Held for Future Use
Cash Working Capital
Materials and Supplies

Prepayments
Pole-Related Construction Work in Progress (CWIP)
General Plant CWIP

These rate base components are functionally assigned to all distribution functional groups, including poles, in a cost of service study and allocated to all customer classes served at the distribution level from KU or LGE. Again, it would be inappropriate to include an arbitrary percentage for "minor appurtenances" but ignore these rate base elements which are allocated to all other customers. In fact, these cost elements which are not considered in the cable television attachment charge calculation would exceed the actual cost of "minor appurtenance" based on the analysis provided in Rebuttal Exhibits MJB-5 and MJB-6.

Q. Has the Commission acknowledged that these types of common costs should be included in carrying charges for cable television attachments?

A. Yes. In its Administrative Case No. 251 dated September 17, 1982, the Commission stated as follows:

> We find it reasonable to allow a contribution by CATV toward the common costs of the utility which cannot be directly allocated to any particular classification of customer. However, each utility which includes such a contribution in its rate development must provide justification for the amount of such contribution which it proposes to include. (Order in Administrative Case No. 251, p. 12.)

Because the common cost items identified in Tables 6 and 7 are functionally assigned to pole-related costs and allocated to all customers receiving service from the Companies' distribution systems in their cost of service studies, it is appropriate to also allocate these costs to cable television pole attachment customers. There is no reason that the common costs identified in Table 6 and 7 should not be allocated to pole attachment customers just as they are to other customers.

Q. Have you performed an analysis updating the charges for current costs, removing a representative portion of the costs to reflect "minor appurtenance" and including the legitimate cost items shown in Tables 6 and 7?

A. Yes. In Rebuttal Exhibits MJB-5and MJB-6, I have updated the charges to reflect current costs (as in Rebuttal Exhibits MJB-1 and MJB- 2), excluded 15% for "minor appurtenances" and included the costs for the items shown in Tables 6 and 7. Table 8, below, compares the current charges to (i) the cost-based charges based on current data for KU and LGE using the rate formula from the last rate cases (as calculated in Rebuttal Exhibit MJB-1 and MJB-2), and (ii) the cost-based charges for KU and LGE after removal of 15% of pole plant costs for "minor appurtenances" and the addition of the legitimate cost items listed in Tables 6 and 7 of my testimony:

Table 8

Company	Current Charges	Charges Updated for Current Cost Data (Using Prior Rate Case Formula)	Charges Updated for Current Cost Data, Removing 15% for "Minor Appurtenances", and adding costs in Table 6 and 7
Kentucky Utilities	$ 9.69	$ 10.58	$10.08

Louisville Gas and Electric	$ 9.11	$ 11.08	$10.36

As can be seen from this table, KU and LGE's current cable television attachment charges are lower than what could be supported by an analysis of current costs, even if 15% of pole costs are removed to reflect appurtenances with the addition of legitimate and supportable common costs.

Q. What is your recommendation regarding the level of the cable television attachment charges?

A. KU and LGE did not propose to modify its cable television attachment charges in these rate case proceedings. As I have shown in Rebuttal Exhibits MJB-1, MJB-2, MJB-5 and MJB-6, higher charges could be supported using historical costs. However, the Companies did not file rate cases based on a historical test year, and there is no basis for adopting higher attachment charges based on historic data any more than there is a basis for adopting the lower attachment charges proposed by Ms. Kravtin based on historic data. Therefore, it is my recommendation that the Commission allow the current cable television rates to remain in effect. Clearly, KCTA has not met its burden of proof in supporting its proposed rates.

Q. How should cable TV attachment charges be set in future rate proceedings?

A. In future rate proceedings, attachment charges should be included as a separate class in the cost of service study and rate design. Essentially, Administrative Case No. 251 established a simplified procedure for developing attachment charges when attachment service was not included as a separate class in the cost of service study. However there was nothing in the Order in Administrative Case No. 251 that would constrain the Company from treating attachments as another service provided by the company in a cost of service study and developing rates using the cost of service information for this class in the future. This would be a more comprehensive and accurate method for developing pole attachments charges than the simplified formula developed in Administrative Case No. 251. If attachment service is treated as a separate class in a rate proceeding, the bare pole costs can be specifically assigned based on the costs for those pole sizes in account 364 to which attachments are made, and joint costs can be allocated to CATV like they are for all other rate classes. This would allow the Company to include the legitimate costs identified in Tables 6 and 7 above. It would also provide an opportunity for the Company to perform a more thorough analysis for KU and LGE to determine the amount of "minor appurtenances", if any, and to support this determination with evidence in the rate proceeding.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Dr. Martin J. Blake**, being duly sworn, deposes and states that he is a Principal of The Prime Group, 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.

Martin J Blake
Dr. Martin J. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of April 2015.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost	Average Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2014			
35'	23,334	$ 12,786,133	$ 547.96
40'	59,312	31,220,040	526.37
	82,646	$ 44,006,173	$ 532.47
Three-User Poles			
40'	59,312	$ 31,220,040	$ 526.37
45'	23,443	35,703,828	1,523.01
	82,755	$ 66,923,867	$ 808.70

	Number of Attachments	Weighted Cost
Two-User Pole Charge		
\$532.47 x .1224 Usage Space Factor = \$ 65.17		
\$ 65.17 x .1806 Annual Carrying Charge = \$ 11.77	-	$ -
Three-User Pole Charge		
\$808.70 x .0759 Usage Space Factor = \$61.38		
\$ 61.38 x .1806 Annual Carrying Charge = \$11.08	87,509	$ 969,802
Weighted Total	87,509	$ 969,802
Weighted Average Annual Cost		$ 11.08

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	7.36%
Depreciation - Sinking Fund	0.67%
Income Tax (1)	3.53%
Property Tax and Insurance	1.10%
Operation and Maintenance (Page 3)	5.40%
Total	18.06%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Short Term Debt	4.54%	0.90%	0.04%
Long Term Debt	42.71%	4.16%	1.78%
Common Equity	52.75%	10.50%	5.54%
Total Capitalization	100.00%		7.36%

Federal and State Income Taxes rate = 38.90%

Income Tax = (0.3890/(1-0.3890) x 0.0554 = 3.53%

LOUISVILLE GAS AND ELECTRIC COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31 , 2014

(1) Labor Charged to 593001 - Poles, Towers and Fixtures Subaccount	$ 74,304	
- Tree Trimming	159,440	
		$ 233,744
Total Labor		71,414,302
Total Administrative and General Expenses		$ 82,720,225

Assignment of a Portion of A & G Expenses to Poles

($233,744/$71,414,302) x $82,720,225 = $270,749

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 474,899
Tree Trimming of Electric Distribution Routes 593004	7,870,074
A & G Expenses Assigned to Poles	270,749
Total	$ 8,615,722

Adder to Annual Carrying Charges for O & M Expenses

$ 8,615,722	Expenses Assigned to Poles	=	5.40%
159,591,768	Plant in Service - Account 364		

KENTUCKY UTILITIES COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost		Average Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2014				
35'	87,362	$ 23,026,482		$ 263.58
40'	140,885	97,115,087		689.32
	228,247	120,141,569		526.37
Three-User Poles				
40'	140,885	$ 97,115,087		$ 689.32
45'	69,359	73,792,804		1,063.93
	210,244	170,907,891		812.90

	Estimated Number of Attachments	Weighted Cost
Two-User Pole Charge		
$526.37 x .1224 Usage Space Factor = $ 64.43		
$ 64.43 x .1714 Annual Carrying Charge = $ 11.04	-	$ -
Three-User Pole Charge		
$812.90 x .0759 Usage Space Factor = $61.70		
$ 61.70 x .1714 Annual Carrying Charge = $10.58	148,680	1,572,480
Weighted Total	148,680	$ 1,572,480
Weighted Average Annual Cost		10.58

KENTUCKY UTILITIES COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	7.23%
Depreciation - Sinking Fund	0.69%
Income Tax (1)	3.58%
Property Tax and Insurance	0.42%
Operation and Maintenance (Page 3)	5.23%
Total	17.14%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Short Term Debt	4.93%	0.64%	0.03%
Long Term Debt	41.51%	3.78%	1.57%
Common Equity	53.56%	10.50%	5.62%
Total Capitalization	100.00%		7.23%

Federal and State Income Taxes rate = 38.90%

Income Tax = (0.3890/(1-0.3890) x 0.0562 = 3.58%

KENTUCKY UTILITIES COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2014

(1) Labor Charged to 593001- Maint of Poles, Towers		
and Fixtures Subaccount	45,882	
- Tree Trimming	406,135	
		$452,017
Total Labor		$100,042,631
Total Administrative and General Expenses		$103,261,735

Assignment of a Portion of A & G Expenses to Poles

($452,017/$100,042,631) x $103,261,735 = $466,562

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures	
Subaccount 593001	$ 619,579
Tree Trimming of Electric Distribution	
Routes 593004	16,088,333
A & G Expenses Assigned to Poles	$466,562
Total	$ 17,174,474

Adder to Annual Carrying Charges for O & M Expenses

$ 17,174,474	Expenses Assigned to Poles	=	5.23%
328,470,051	Plant in Service - Account 364		

Kravtin Attachment 3, Table 1

Rebuttal Exhibit MJB-3

Inconsistent discount rates used to obtain the same $1,000 present value

Comparison of Non-Levelized and Levelized Capital Recovery Carrying Charge Approaches	
(a) Average Service Life	35
(b) Ratio Net to Gross Investment	0.5
(c) Straight Line Depreciation [1/(a)] as Fixed % of Gross Investment	2.86%
(d) Straight Line Depreciation [1/(a)] as Average % of Net Investment	5.72%
(e)Authorized Rate of Return (ROR) /Discount Factor (DF) as Fixed % of Net Investment	8.32%
(f)Authorized Rate of Return (ROR) /Discount Factor (DF) as Average % of Gross Investment	4.16%
(g) Sinking-Fund Depreciation [(f/(1+f)^(a-1)] as Fixed % of Gross Investment	1.31%

	Non-Levelized (Straight Line Depreciation) Capital Carrying Charges							Levelized (Sinking Fund Depreciation) Capital Carrying Charges per Kravtin					
Year (1)	Net Investment (2)	Return Charge (3)=(2) x(4)	ROR as % Net Inv (4)	ROR as % Gross Inv (5)	Straight Line Depreciation (6)=(c)xGross	Capital Carry Charges (7)=(3)+(6)	Present Val @8.32% (8)	Gross Investment (9)	Return Charge (10)	ROR as % Gross Inv (11)	Sinking Fund Depreciation (12)=(g)*Gross	Capital Carry Charges (13)=(10)+(12)	Present Val @Gross RoR (14)
1	$ 1,000.00	$ 83.20	8.32%	8.32%	$ 28.57	$ 111.77	$103.19	$ 1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 52.56
2	971.43	80.82	8.32%	8.08%	28.57	$ 109.39	93.23	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 50.46
3	942.86	78.45	8.32%	7.84%	28.57	$ 107.02	84.20	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 48.45
4	914.29	76.07	8.32%	7.61%	28.57	$ 104.64	76.01	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 46.51
5	885.71	73.69	8.32%	7.37%	28.57	$ 102.26	68.58	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 44.65
6	857.14	71.31	8.32%	7.13%	28.57	$ 99.89	61.84	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 42.87
7	828.57	68.94	8.32%	6.89%	28.57	$ 97.51	55.73	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 41.16
8	800.00	66.56	8.32%	6.66%	28.57	$ 95.13	50.19	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 39.51
9	771.43	64.18	8.32%	6.42%	28.57	$ 92.75	45.18	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 37.94
10	742.86	61.81	8.32%	6.18%	28.57	$ 90.38	40.64	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 36.42
11	714.29	59.43	8.32%	5.94%	28.57	$ 88.00	36.53	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 34.97
12	685.71	57.05	8.32%	5.71%	28.57	$ 85.62	32.82	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 33.57
13	657.14	54.67	8.32%	5.47%	28.57	$ 83.25	29.45	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 32.23
14	628.57	52.30	8.32%	5.23%	28.57	$ 80.87	26.42	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 30.94
15	600.00	49.92	8.32%	4.99%	28.57	$ 78.49	23.67	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 29.71
16	571.43	47.54	8.32%	4.75%	28.57	$ 76.11	21.19	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 28.52
17	542.86	45.17	8.32%	4.52%	28.57	$ 73.74	18.95	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 27.38
18	514.29	42.79	8.32%	4.28%	28.57	$ 71.36	16.93	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 26.29
19	485.71	40.41	8.32%	4.04%	28.57	$ 68.98	15.11	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 25.24
20	457.14	38.03	8.32%	3.80%	28.57	$ 66.61	13.47	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 24.23
21	428.57	35.66	8.32%	3.57%	28.57	$ 64.23	11.99	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 23.26
22	400.00	33.28	8.32%	3.33%	28.57	$ 61.85	10.66	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 22.33
23	371.43	30.90	8.32%	3.09%	28.57	$ 59.47	9.46	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 21.44
24	342.86	28.53	8.32%	2.85%	28.57	$ 57.10	8.39	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 20.58
25	314.29	26.15	8.32%	2.61%	28.57	$ 54.72	7.42	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 19.76
26	285.71	23.77	8.32%	2.38%	28.57	$ 52.34	6.55	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 18.97
27	257.14	21.39	8.32%	2.14%	28.57	$ 49.97	5.77	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 18.22
28	228.57	19.02	8.32%	1.90%	28.57	$ 47.59	5.08	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 17.49
29	200.00	16.64	8.32%	1.66%	28.57	$ 45.21	4.45	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 16.79
30	171.43	14.26	8.32%	1.43%	28.57	$ 42.83	3.90	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 16.12
31	142.86	11.89	8.32%	1.19%	28.57	$ 40.46	3.40	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 15.47
32	114.29	9.51	8.32%	0.95%	28.57	$ 38.08	2.95	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 14.86
33	85.71	7.13	8.32%	0.71%	28.57	$ 35.70	2.55	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 14.26
34	57.14	4.75	8.32%	0.48%	28.57	$ 33.33	2.20	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 13.69
35	28.57	2.38	8.32%	0.24%	28.57	$ 30.95	1.89	1,000.00	$ 41.60	4.16%	$ 13.15	$ 54.75	$ 13.15
	TOTAL/AVG	$1,497.60	8.32%	4.28%	$1,000.00	$2,497.60	$1,000.00		$1,456.00	4.16%	$460.14	$1,916.14	$1,000.00

Result of using different discount rates

Rebuttal Exhibit MJB-4

Comparison of Non-Levelized and Levelized Capital Recovery Carrying Charge Approaches

(a) Average Service Line	35
(b) Ratio Net to Gross Investment	0.5
(c) Straight Line Depreciation [1/(a)] as Fixed % of Gross Investment	2.86%
(d) Straight Line Depreciation [1/(a)] as Average % of Net Investment	5.72%
(e) Authorized Rate of Return (ROR)/Discount Factor (DF) as Fixed % if Net Investment	8.32%
(e) Authorized Rate of Return (ROR)/Discount Factor (DF) as Average % of Gross Investment	4.16%
(g) Sinking-Fund Depreciation [(f/1+f)^(a-1)] as Fixed % of Gross Investment	1.31%

	Non-Levelized (Straight Line Depreciation) Capital Carrying Charges							**Levelized (Sinking Fund Depreciation) Captial Carrying Charges per Kravtin**					
Year (1)	Net Investment (2)	Return Charge (3)=(2)x(4)	Return as % Net Inv (4)	Return as % Gross Inv (5)	Straight Line Depreciation (6)=(c)xGross	Capital Carry Charges (7)=(3)+(6)	Present Val @8.32% (8)	Gross Investment (9)	Return Charge (10)	Return as % Gross Inv (11)	Sinking Fund Depreciation '(12)=(g)*Gross	Captial Carry Charges (13)=(10)+(12)	Present Val @8.32% (14)
1	1,000.00	83.20	8.32%	8.32%	28.57	111.77	103.19	1,000.00	41.60	4.16%	13.15	54.75	50.54
2	971.43	80.82	8.32%	8.08%	28.57	109.39	93.23	1,000.00	41.60	4.16%	13.15	54.75	46.66
3	942.86	78.45	8.32%	7.84%	28.57	107.02	84.20	1,000.00	41.60	4.16%	13.15	54.75	43.08
4	914.29	76.07	8.32%	7.61%	28.57	104.64	76.01	1,000.00	41.60	4.16%	13.15	54.75	39.77
5	885.71	73.69	8.32%	7.37%	28.57	102.26	68.58	1,000.00	41.60	4.16%	13.15	54.75	36.71
6	857.14	71.31	8.32%	7.13%	28.57	99.89	61.84	1,000.00	41.60	4.16%	13.15	54.75	33.89
7	828.57	68.94	8.32%	6.89%	28.57	97.51	55.73	1,000.00	41.60	4.16%	13.15	54.75	31.29
8	800.00	66.56	8.32%	6.66%	28.57	95.13	50.19	1,000.00	41.60	4.16%	13.15	54.75	28.89
9	771.43	64.18	8.32%	6.42%	28.57	92.75	45.18	1,000.00	41.60	4.16%	13.15	54.75	26.67
10	742.86	61.81	8.32%	6.18%	28.57	90.38	40.64	1,000.00	41.60	4.16%	13.15	54.75	24.62
11	714.29	59.43	8.32%	5.94%	28.57	88.00	36.53	1,000.00	41.60	4.16%	13.15	54.75	22.73
12	685.71	57.05	8.32%	5.71%	28.57	85.62	32.82	1,000.00	41.60	4.16%	13.15	54.75	20.98
13	657.14	54.67	8.32%	5.47%	28.57	83.25	29.45	1,000.00	41.60	4.16%	13.15	54.75	19.37
14	628.57	52.30	8.32%	5.23%	28.57	80.87	26.42	1,000.00	41.60	4.16%	13.15	54.75	17.88
15	600.00	49.92	8.32%	4.99%	28.57	78.49	23.67	1,000.00	41.60	4.16%	13.15	54.75	16.51
16	571.43	47.54	8.32%	4.75%	28.57	76.11	21.19	1,000.00	41.60	4.16%	13.15	54.75	15.24
17	542.86	45.17	8.32%	4.52%	28.57	73.74	18.95	1,000.00	41.60	4.16%	13.15	54.75	14.07
18	514.29	42.79	8.32%	4.28%	28.57	71.36	16.93	1,000.00	41.60	4.16%	13.15	54.75	12.99
19	485.71	40.41	8.32%	4.04%	28.57	68.98	15.11	1,000.00	41.60	4.16%	13.15	54.75	11.99
20	457.14	38.03	8.32%	3.80%	28.57	66.61	13.47	1,000.00	41.60	4.16%	13.15	54.75	11.07
21	428.57	35.66	8.32%	3.57%	28.57	64.23	11.99	1,000.00	41.60	4.16%	13.15	54.75	10.22
22	400.00	33.28	8.32%	3.33%	28.57	61.85	10.66	1,000.00	41.60	4.16%	13.15	54.75	9.44
23	371.43	30.90	8.32%	3.09%	28.57	59.47	9.46	1,000.00	41.60	4.16%	13.15	54.75	8.71
24	342.86	28.53	8.32%	2.85%	28.57	57.10	8.39	1,000.00	41.60	4.16%	13.15	54.75	8.04
25	314.29	26.15	8.32%	2.61%	28.57	54.72	7.42	1,000.00	41.60	4.16%	13.15	54.75	7.42
26	285.71	23.77	8.32%	2.38%	28.57	52.34	6.55	1,000.00	41.60	4.16%	13.15	54.75	6.85
27	257.14	21.39	8.32%	2.14%	28.57	49.97	5.77	1,000.00	41.60	4.16%	13.15	54.75	6.33
28	228.57	19.02	8.32%	1.90%	28.57	47.59	5.08	1,000.00	41.60	4.16%	13.15	54.75	5.84
29	200.00	16.64	8.32%	1.66%	28.57	45.21	4.45	1,000.00	41.60	4.16%	13.15	54.75	5.39
30	171.43	14.26	8.32%	1.43%	28.57	42.83	3.90	1,000.00	41.60	4.16%	13.15	54.75	4.98
31	142.86	11.89	8.32%	1.19%	28.57	40.46	3.40	1,000.00	41.60	4.16%	13.15	54.75	4.60
32	114.29	9.51	8.32%	0.95%	28.57	38.08	2.95	1,000.00	41.60	4.16%	13.15	54.75	4.24
33	85.71	7.13	8.32%	0.71%	28.57	35.70	2.55	1,000.00	41.60	4.16%	13.15	54.75	3.92
34	57.14	4.75	8.32%	0.48%	28.57	33.33	2.20	1,000.00	41.60	4.16%	13.15	54.75	3.62
35	28.57	2.38	8.32%	0.24%	28.57	30.95	1.89	1,000.00	41.60	4.16%	13.15	54.75	3.34
	TOTAL/AVG	$1,497.60	8.32%	4.28%	$1,000.00	$2,497.60	$1,000.00		$1,456.00	4.16%	$460.15	$1,916.15	$617.89

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity		Installed Cost		Average Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2014					
Two-User Poles (Less 15% for Appurtenances)					
35'	23,334	$	10,868,213	$	465.77
40'	59,312		26,537,034		447.41
	82,646	$	37,405,247	$	452.60
Three-User Poles (Less 15% for Appurtenances)					
40'	59,312	$	26,537,034	$	447.41
45'	23,443		30,348,254		1,294.56
	82,755	$	56,885,287	$	687.39
Common Plant (Page 4)	82,755	$	3,477,177	$	42.02
Cash Working Capital (Page 3)	82,755	$	450,275	$	5.44

Pole Cost (Space Factor determined from 3 user Pole)

		Number of Attachments		Weighted Cost
Pole	$687.39 x .0759 Usage Space Factor = $52.17			
	$ 52.17 x .1899 Annual Carrying Charge (ACC) = $9.91	87,509	$	866,965
Common	$42.02 x .0759 x 0.1266 = $0.40			35,322
CWC	$5.44 x .0759 x 0.1088 = $0.04			3,933
	Weighted Total	87,509	$	906,220
	Weighted Average Annual Cost		$	10.36

LOUISVILLE GAS AND ELECTRIC COMPANY

Calculation Of Annual Carrying Charge

	Poles	General Plant	Working Capital
Proposed Rate of Return	7.36%	7.36%	7.36%
Depreciation - Sinking Fund	0.67%	0.67%	
Income Tax (1)	3.53%	3.53%	3.53%
Property Tax and Insurance	1.10%	1.10%	
Operation and Maintenance (Page 3)	6.33%		
Total	18.99%	12.66%	10.88%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Short Term Debt	4.54%	0.90%	0.04%
Long Term Debt	42.71%	4.16%	1.78%
Common Equity	52.75%	10.50%	5.54%
Total Capitalization	100.00%		7.36%

Federal and State Income Taxes rate = 38.90%

Income Tax = (0.3890/(1-0.3890) x 0.0554 = 3.53%

LOUISVILLE GAS AND ELECTRIC COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31 , 2014

(1) Labor Charged to 593001 - Poles, Towers		
and Fixtures Subaccount	$ 74,304	
- Tree Trimming	159,440	
		$ 233,744
Total Labor		71,414,302
Total Administrative and General Expenses		$ 82,720,225

Assignment of a Portion of A & G Expenses to Poles

($233,744/$71,414,302) x $82,720,225 = $270,749

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures	
Subaccount 593001	$ 474,899
Tree Trimming of Electric Distribution	
Routes 593004	7,870,074
A & G Expenses Assigned to Poles	270,749
Other Common Expenses (Page 4)	1,490,253
Total	$ 10,105,975

Adder to Annual Carrying Charges for O & M Expenses

$$\frac{\$\ 10{,}105{,}975 \quad \text{Expenses Assigned to Poles}}{159{,}591{,}768 \quad \text{Plant in Service - Account 364}} = 6.33\%$$

KENTUCKY UTILITIES COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost		Average Installed Cost
Weighted Average Bare Pole Cost as of10/31/2014				
Two-User Poles (Less 15% for Appurtenances)				
35'	87,362	$ 19,572,510		$ 224.04
40'	140,885	82,547,824		585.92
	228,247	102,120,334		447.41
Three-User Poles				
40'	140,885	$ 82,547,824		$ 585.92
45'	69,359	62,723,883		904.34
	210,244	145,271,707		690.97
Common Plant (Page 4)	210,244	$6,318,932		$ 30.06
Cash Working Capital (Page 3)	210,244	1,215,818		$ 5.78

		Estimated Number of Attachments	Weighted Cost
Two-User Pole Charge			
	$447.41 x .1224 Usage Space Factor = $ 54.76		
	$ 54.76 x .1861 Annual Carrying Charge = $ 10.19	-	$ -
Three-User Pole Charge			
Pole	$690.97 x .0759 Usage Space Factor = $52.44		
	$ 52.44 x .1861 Annual Carrying Charge = $9.76	148,680	1,450,979
Common	$30.06 x .0759 x 0.1191 = $0.27		40,405
CWC	$5.78 x .0759 x 0.1081 = $0.05		7,052
	Weighted Total	148,680	$ 1,498,436
	Weighted Average Annual Cost		10.08

KENTUCKY UTILITIES COMPANY

Calculation Of Annual Carrying Charge

	Poles	General Plant	Working Capital
Proposed Rate of Return	7.23%	7.23%	7.23%
Depreciation - Sinking Fund	0.69%	0.69%	
Income Tax (1)	3.58%	3.58%	3.58%
Property Tax and Insurance	0.42%	0.42%	
Operation and Maintenance (Page 3)	6.70%		
Total	18.61%	11.91%	10.81%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Short Term Debt	4.93%	0.64%	0.03%
Long Term Debt	41.51%	3.78%	1.57%
Common Equity	53.56%	10.50%	5.62%
Total Capitalization	100.00%		7.23%

Federal and State Income Taxes rate = 38.90%

Income Tax = (0.3890/(1-0.3890) x 0.0562 = 3.58%

KENTUCKY UTILITIES COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2014

(1) Labor Charged to 593001- Maint of Poles, Towers and Fixtures Subaccount	45,882	
- Tree Trimming	406,135	
		$452,017
Total Labor		$100,042,631
Total Administrative and General Expenses		$103,261,735

Assignment of a Portion of A & G Expenses to Poles

($452,017/$100,042,631) x $103,261,735 = $466,562

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$	619,579
Tree Trimming of Electric Distribution Routes 593004		16,088,333
A & G Expenses Assigned to Poles		$466,562
Other Common Expenses (Page 4)		$4,817,952
Total	$	21,992,426

Adder to Annual Carrying Charges for O & M Expenses

$ 21,992,426	Expenses Assigned to Poles	=	6.70%
328,470,051	Plant in Service - Account 364		

KENTUCKY UTILITIES COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost		Average Installed Cost
Weighted Average Bare Pole Cost as of10/31/2014				
Two-User Poles (Less 15% for Appurtenances)				
35'	87,362	$ 21,875,158		$ 250.40
40'	140,885	92,259,333		654.86
	228,247	114,134,491		500.05
Three-User Poles				
40'	140,885	$ 92,259,333		$ 654.86
45'	69,359	70,103,164		1,010.73
	210,244	162,362,496		772.26
Common Plant (Page 4)	210,244	$7,062,335		$ 33.59
Cash Working Capital (Page 3)	210,244	1,358,855		$ 6.46

		Estimated Number of Attachments	Weighted Cost
Two-User Pole Charge			
	$500.05 x .1224 Usage Space Factor = $ 61.21		
	$ 61.21 x .1861 Annual Carrying Charge = $ 11.39	-	$ -
Three-User Pole Charge			
Pole	$772.26 x .0759 Usage Space Factor = $58.61		
	$ 58.61 x .1861 Annual Carrying Charge = $10.91	148,680	1,621,683
Common	$33.59 x .0759 x 0.1191 = $0.30		45,159
CWC	$6.46 x .0759 x 0.1081 = $0.05		7,881
	Weighted Total	148,680	$ 1,674,723
	Weighted Average Annual Cost		11.26

KENTUCKY UTILITIES COMPANY

Calculation Of Annual Carrying Charge

	Poles	General Plant	Working Capital
Proposed Rate of Return	7.23%	7.23%	7.23%
Depreciation - Sinking Fund	0.69%	0.69%	
Income Tax (1)	3.58%	3.58%	3.58%
Property Tax and Insurance	0.42%	0.42%	
Operation and Maintenance (Page 3)	6.70%		
Total	18.61%	11.91%	10.81%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Short Term Debt	4.93%	0.64%	0.03%
Long Term Debt	41.51%	3.78%	1.57%
Common Equity	53.56%	10.50%	5.62%
Total Capitalization	100.00%		7.23%

Federal and State Income Taxes rate = 38.90%

Income Tax = (0.3890/(1-0.3890) x 0.0562 = 3.58%

KENTUCKY UTILITIES COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2014

(1) Labor Charged to 593001- Maint of Poles, Towers and Fixtures Subaccount	45,882	
- Tree Trimming	406,135	
		$452,017
Total Labor		$100,042,631
Total Administrative and General Expenses		$103,261,735

Assignment of a Portion of A & G Expenses to Poles

($452,017/$100,042,631) x $103,261,735 = $466,562

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 619,579
Tree Trimming of Electric Distribution Routes 593004	16,088,333
A & G Expenses Assigned to Poles	$466,562
Other Common Expenses (Page 4)	$4,817,952
Total	$ 21,992,426

Adder to Annual Carrying Charges for O & M Expenses

$ 21,992,426	Expenses Assigned to Poles	=	6.70%
328,470,051	Plant in Service - Account 364		

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2014-00371**
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2014-00372**

REBUTTAL TESTIMONY

OF

WILLIAM E. AVERA
AND
ADRIEN M. MCKENZIE

on behalf of

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: April 14, 2015

REBUTTAL TESTIMONY

OF

WILLIAM E. AVERA
AND
ADRIEN M. MCKENZIE

TABLE OF CONTENTS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAMES AND BUSINESS ADDRESS.

A1. Our names are William E. Avera and Adrien M. McKenzie. Our business address is 3907 Red River, Austin, Texas.

Q2. DID YOU PREVIOUSLY SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A2. Yes, we did.

Q3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS CASE?

A3. Our purpose is to respond to the testimony of Dr. J. Randall Woolridge, submitted on behalf of the Kentucky Office of Attorney General ("OAG"), Mr. Richard Baudino, on behalf of the Kentucky Industrial Utility Consumers ("KIUC"), and Mr. Steve W. Chriss, on behalf of Wal-Mart Stores East, LP and Sam's East, Inc., concerning the fair rate of return on equity ("ROE") that Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies") should be authorized to earn on their investment in providing electric and gas utility service. In addition, we also respond to the capital structure recommendations of Dr. Woolridge.

Q4. HAVE YOU PREPARED WORKPAPERS SUPPORTING YOUR REBUTTAL TESTIMONY?

A4. Yes. Workpapers including supporting documents referenced in our rebuttal testimony and related exhibits are attached as Appendix A.

Q5. PLEASE SUMMARIZE THE PRINCIPAL CONCLUSIONS OF YOUR REBUTTAL TESTIMONY.

A5. Investors have many options for their funds and competition for investment dollars is intense. The cost of equity recommendations of Dr. Woolridge and Mr. Baudino are simply too low and fail to reflect the risk perceptions and return requirements of real-world investors in the capital markets. Our rebuttal testimony demonstrates that:

- *The analyses conducted by Dr. Woolridge and Mr. Baudino are flawed and incomplete, and result in cost of equity estimates that are far below investors' required return;*
- *The Companies must be granted an opportunity to earn a return that is competitive with other utilities:*
  - *Allowed ROEs, which average approximately 10.1% to 10.3% for the risk-comparable electric utilities referenced by Dr. Woolridge and Mr. Baudino, demonstrate that their recommendations are too low.*
  - *The recommendations of Dr. Woolridge and Mr. Baudino are also inadequate to compensate investors in the Companies when evaluated against the results of the expected earnings approach for other electric utilities, which suggest an average ROE on the order of 10.2%.*

With respect to Dr. Woolridge's and Mr. Baudino's analyses and conclusions, our rebuttal testimony shows that:

- *In applying quantitative methods to estimate the cost of equity, Dr. Woolridge incorporated data that does not reflect investors' expectations and failed to exclude illogical results, which imparts a downward bias to his conclusions;*
- *Dr. Woolridge made no attempt to eliminate illogical data in applying the DCF model, which included numerous negative growth rates. Similarly, Mr. Baudino also failed to evaluate the reasonableness of individual DCF estimates. As a result, their conclusions are unreliable and should be ignored;*
- *Dr. Woolridge's and Mr. Baudino's application of the DCF model based on the internal, "br" growth rate is flawed and incomplete;*
- *The CAPM results reported by Dr. Woolridge were based on a hodge-podge of historical data that failed to reflect forward-looking expectations, particularly in light of current conditions in the capital*

markets;

- *Similarly, Mr. Baudino's application of the CAPM was compromised by reliance on historical data, while his forward-looking approach was marred by methodological shortcomings and inconsistencies;*
- *Because of flaws in the screening criteria and data used by Dr. Woolridge and Mr. Baudino, their proxy groups of electric utilities should be rejected;*
- *Dr. Woolridge's and Mr. Baudino's characterization of capital market conditions is flawed and incomplete, and fails to reflect widely-held expectations for higher capital costs; and,*
- *The failure of Mr. Baudino and Dr. Woolridge to consider the impact of flotation costs contradicts the findings of the financial literature and the economic requirements underlying a fair rate of return on equity.*

With respect to Dr. Woolridge's recommended capital structure, our rebuttal testimony demonstrates that there is no basis for the hypothetical equity ratio he selects. In addition, we address the comments and observations offered by Mr. Chriss, which also support our findings that the recommendations of Dr. Woolridge and Mr. Baudino are too low. Finally, our rebuttal testimony demonstrates that Dr. Woolridge's and Mr. Baudino's criticisms of our alternative applications and conclusions are misguided and should be ignored. Our rebuttal testimony continues to support the reasonableness of a 10.64% ROE for the Companies.

II. RECOMMENDATIONS FAIL REGULATORY STANDARDS

Q6. IS IT WIDELY ACCEPTED THAT A UTILITY'S ABILITY TO ATTRACT CAPITAL MUST BE CONSIDERED IN ESTABLISHING A FAIR RATE OF RETURN?

A6. Yes. This is a fundamental standard underlying the regulation of public utilities. The Supreme Court's *Bluefield* and *Hope* decisions established that a regulated utility's authorized returns on capital must be sufficient to assure investors' confidence and adequate, under efficient and economical management, to maintain and support a utility's credit and enable it to raise money necessary to provide safe and reliable service to its customers.[1]

Beyond these standards, one fundamental requirement that any ROE recommendation must satisfy before it can be considered reasonable is that it must grant the Companies the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments of similar risk if they are to maintain its financial flexibility and ability to attract capital. Dr. Woolridge and Mr. Baudino clearly recognized,[2] but then ignored, these fundamental standards.

Q7. HAVE OTHER REGULATORS RECENTLY RECOGNIZED THE IMPORTANCE OF THESE FUNDAMENTAL STANDARDS IN EVALUATING A FAIR ROE?

A7. Yes. The Federal Energy Regulatory Commission ("FERC") recently affirmed that its "ultimate task is to ensure that the resulting ROE satisfies the requirements of *Hope* and *Bluefield*."[3] While FERC looks initially to the DCF methodology when evaluating a fair ROE, it has also made clear that it is the result reached, not the method used, that determines whether an ROE is just and reasonable.[4] As FERC observed:

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of

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[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 694 (1923) ("*Bluefield*"); *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) ("*Hope*").

[2] For example, Dr. Woolridge (p. 3) noted that the ROE must "comparable to returns investors expect to earn on other investments of similar risk." Similarly, Mr. Baudino (pp. 13-14) also recognized these fundamental standards underlying a fair ROE.

[3] *Coakley v. Bangor Hydro-Electric Co.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 144 (2014) ("Opinion No. 531").

[4] *See, e.g.*, Opinion No. 531 at P 142.

> return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses in determining where to set a public utility's ROE within the range of reasonable returns . . .[5]

FERC concluded that due to anomalous capital market conditions, a mechanical application of the DCF model would result in an ROE that was insufficient to meet regulatory standards, and that "it is necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark methodologies and state commission-approved ROEs," to determine a just and reasonable ROE.[6] In Opinion No. 531, FERC found that risk premium, CAPM, and expected earnings methodologies directly comparable to those applied in our direct testimony in this case were informative and relied on these analyses to set the just and reasonable point ROE at the upper end of the DCF range.

Q8. DID DR. WOOLRIDGE OR MR. BAUDINO TEST THEIR ROE RECOMMENDATIONS AGAINST THESE FUNDAMENTAL REGULATORY REQUIREMENTS?

A8. No. Expected earned rates of return for other utilities provide one useful benchmark to gauge the reasonableness of the ROE recommendation of Dr. Woolridge and Mr. Baudino, but neither witness performed this test.[7] The expected earnings approach is predicated on the comparable earnings test, which developed as a direct result of the Supreme Court decisions in *Bluefield* and *Hope*. This test recognizes that investors compare the allowed ROE with returns available from other alternatives of comparable risk.

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[5] *Id.* at P 41. Application of the two-step DCF method without the "mid-point of the upper half of the range" adjustment would have resulted in an ROE of only 9.39%, a value FERC found unreasonable. *Id* at P 142.

[6] Opinion No. 531 at P 145.

[7] Dr. Woolridge (pp. 27-28) cited to earned returns for his electric proxy group of approximately 9.0%-12.0%, and approximately 10.0%-12.0% for his gas companies, but made no inference between these results and his own 8.75% ROE recommendation.

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, the expected earnings approach provides a direct guide to 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, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q9. DID MR. BAUDINO RECOGNIZE THE ECONOMIC PREMISE UNDERLYING THE EXPECTED EARNINGS APPROACH?

A9. Yes. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. As Baudino recognized, economists refer to the returns that an investor must forgo by not being invested in the next best alternative as "opportunity costs."[8] Mr. Baudino went on to explain that, "One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative."[9]

Q10. DESPITE RECOGNIZING THE REGULATORY STANDARDS UNDERLYING YOUR REFERENCE TO EARNINGS ON BOOK VALUE, DR. WOOLRIDGE AND MR. BAUDINO ARE CRITICAL OF THIS

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[8] Baudino Direct at 13.
[9] *Id.*

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

A10. Yes. A textbook prepared for the Society of Utility and Regulatory 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.[10] The *Practitioner's Guide* notes that the comparable earnings method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases,[11] as well as sound regulatory economics. Similarly, *New Regulatory Finance* concluded that, "because 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."[12] More recently, FERC concluded that the expected earnings approach "can be useful in validating our ROE recommendation . . . . given its close relationship to the comparable earnings standard that originated in *Hope*, and the fact that it is used by investors to estimate the ROE that a utility will earn in the future."[13]

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[10] Parcell, David C., THE COST OF CAPITAL – A PRACTITIONER'S GUIDE at 115-116 (2010).
[11] *Id.*
[12] Morin, Roger A., *New Regulatory Finance*, at 395 (Public Utilities Reports, Inc. 2006).
[13] Opinion No. 531 at P 147. The Virginia 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 continues to confirm the relevance of 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).

Q11. DO YOU AGREE WITH MR. BAUDINO (P. 46) THAT MARKET DATA IS THE ONLY USEFUL BENCHMARK IN EVALUATING INVESTORS' OPPORTUNITY COSTS?

A11. No. While we agree that market-based models are certainly important tools in estimating investors' required rate of return, this in no way invalidates the usefulness of the expected earnings approach. In fact, this is one of its advantages.

It is a very simple, conceptual principle that when evaluating two investments of comparable risk, investors will choose the alternative with the higher expected return. If the Companies are only allowed the opportunity to earn an 8.75% or 8.60% return on the book value of its equity investment, as recommended by Dr. Woolridge and Mr. Baudino, while other electric utilities are expected to earn an average of 10.68%,[14] the implications are clear – the Companies' investors will be denied the ability to earn their opportunity cost.

Moreover, regulators do not set the returns that investors earn in the capital markets – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to 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, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

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[14] Value Line reports an average expected return on book equity for 2018-20 of 10.68% for the electric utility industry. The Value Line Investment Survey (Dec. 19, 2014, Jan. 30 & Feb. 20, 2015).

Q12. WHAT ROE IS IMPLIED BY THE EXPECTED EARNINGS APPROACH FOR THE PROXY GROUPS OF ELECTRIC UTILITIES REFERENCED BY OAG AND KIUC?

A12. The year-end returns on common equity projected by Value Line Investment Survey ("Value Line") over its forecast horizon for the firms in the electric utility proxy groups referenced by OAG and KIUC are shown on Exhibit No. 12. Once adjusted to mid-year, reference to expected earnings implied an annual average cost of equity for the utilities referenced by Dr. Woolridge of 10.07%, or 10.33% for Mr. Baudino's proxy group. These book return estimates are an "apples to apples" comparison to the 8.75% to 8.60% ROE recommendations of OAG and KIUC, respectively.

Q13. DO YOU AGREE WITH DR. WOOLRIDGE (PP. 80-81) THAT IT IS NECESSARY TO EXAMINE MARKET-TO-BOOK RATIOS ("M/B") IN APPLYING THE EXPECTED EARNINGS APPROACH?

A13. No. Traditional applications of the expected earnings approach do not involve an M/B adjustment. Nor is such an adjustment recommended in recognized texts such as *New Regulatory Finance.*[15]

Q14. IS THERE A CLEAR LINK BETWEEN M/B FOR UTILITIES AND ALLOWED RATES OF RETURN?

A14. No. Underlying Dr. Woolridge's criticism is the supposition that utility earnings are too high and that regulators should set an ROE to produce an M/B of approximately 1.0. This is misguided. For example, *Regulatory Finance: Utilities Cost of Capital* noted that:

> The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to

[15] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006).

> produce an M/B of 1.0, presumes that investors are irrational. They commit capital to a utility with an M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is certainly not a realistic or accurate view of regulation.[16]

With M/B for most utilities above 1.0, Dr. Woolridge is suggesting that, unless book value grows rapidly, regulators should establish equity returns that will cause share prices to fall. Given the regulatory imperative of preserving a utility's ability to attract capital, this would be a truly nonsensical result. M/B is determined by investors in the stock market, and a utility would be foreclosed from attracting capital if regulators were to push M/B to 1.0 while other firms command prices well in excess of 1.0 times book value.

Q15. ARE ADJUSTMENTS BASED ON M/B A COMMON FEATURE IN DETERMINING ALLOWED ROES FOR UTILITIES?

A15. No. While arguments regarding the implications of an M/B greater than 1.0 are not uncommon, we are not aware of a single instance in recent history in which a state regulator has approved an M/B adjustment in establishing a fair ROE. Similarly, FERC explicitly recognized the fallacy of relying on M/B in applying the expected earnings approach in a March 2015 decision:

> The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's market cost of equity, because those returns on book equity help investors determine the opportunity cost of investing in that particular utility instead of other companies of comparable risk. . . . [C] considering market-to-book ratios in an expected earnings study is inconsistent with the purpose of the comparable earnings model.[17]

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[16] *Id.* at 376.

[17] *Opinion No. 531-B,* 150 FERC ¶ 61,165 at P 128, 132 (2015) ("Opinion No. 531-B").

Q16. CAN ALLOWED ROES ALSO BE USED TO EVALUATE WHETHER THE RECOMMENDATIONS OF DR. WOOLRIDGE AND MR. BAUDINO ARE SUFFICIENT TO MEET REGULATORY STANDARDS?

A16. 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. While the ROEs approved in other jurisdictions do not constrain the KPSC's decision-making in this proceeding, it is important to understand that there would be a disincentive for investors to provide equity capital if the Commission were to apply an unreasonably low ROE to the Companies, compared to entities of comparable risk.

Q17. HOW DO THE 8.75% AND 8.60% ROE RECOMMENDATIONS OF DR. WOOLRIDGE AND MR. BAUDINO IN THIS PROCEEDING COMPARE TO AUTHORIZED RETURNS FOR THE UTILITIES IN THE PROXY GROUPS THEY USED TO ESTIMATE THE COST OF EQUITY?

A17. The ROE recommendations of Dr. Woolridge and Mr. Baudino fall well below average returns authorized for other utilities. As shown on Exhibit No. 13, data reported by Value Line indicates that the average authorized ROE for the firms in Dr. Woolridge's and Mr. Baudino's electric proxy groups is 10.16%, which is between 141 to 156 basis points higher than their recommendations for the Companies.

Q18. WHAT ARE THE IMPLICATIONS OF SETTING AN ALLOWED ROE FAR BELOW THE RETURNS AVAILABLE FROM OTHER INVESTMENTS OF COMPARABLE RISK?

A18. 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 of these outcomes violate regulatory standards.

Q19. WHAT OTHER PITFALLS ARE ASSOCIATED WITH AN ROE THAT FALLS BELOW THOSE AUTHORIZED FOR OTHER COMPARABLE COMPANIES?

A19. Adopting an ROE for the Companies that is well below the ROEs for comparable utilities could lead investors to view the KPSC's regulatory framework as unsupportive, an outcome that would undermine investors' willingness to support future capital availability for investment in Kentucky. Security analysts study regulatory orders in order to advise investors where to invest their money. Moody's Investors Service ("Moody's") noted that, "[f]undamentally, the regulatory environment is the most important driver of our outlook."[18] Similarly, Standard & Poor's Corporation ("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."[19]

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[18] Moody's Investors Service, *Regulation Will Keep Cash Flow Stable As Major Tax Break Ends*, *Industry Outlook* (Feb. 19, 2014).
[19] Standard & Poor's Corporation, *Key Credit Factors For The Regulated Utilities Industry*, *RatingsDirect* (Nov. 19, 2013).

If the KPSC's actions instill confidence that the regulatory environment is supportive, investors will provide the necessary capital, even in times of turmoil in the financial markets. In evaluating the Companies' ROE in this case, the KPSC has an opportunity to show that it recognizes the importance of continuity and a balanced regulatory regime.

Meanwhile, adopting OAG's or KIUC's recommendation would likely increase the cost of capital for the Companies and the other utilities in the state. The dangers of such an outcome were recognized at FERC. A Presiding Judge recently noted that "if ROE is set substantially below 10% for long periods … it could negatively impact future investment," and concluded that if "investment is substantially limited in the future, it will have a negative impact upon operational needs, reliability, and ultimately ratepayers' future costs."[20] It is only rational for potential investors to consider the regulatory treatment afforded to the Companies in evaluating whether to commit new capital to Kentucky jurisdictional utilities, and at what cost.

Q20. WHAT OTHER EVIDENCE INDICATES THAT THE ROE RECOMMENDATIONS OF DR. WOOLRIDGE AND MR. BAUDINO FAIL TO MEET REGULATORY STANDARDS?

A20. As discussed in our direct testimony,[21] 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. The idea that investors evaluate utilities against the returns available from other investment alternatives – including the low-risk companies in our Non-Utility Group – is a fundamental cornerstone of modern financial theory. Aside from this theoretical underpinning, any casual

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[20] *Martha Coakley, Massachusetts Attorney General*, 144 FERC ¶ 63,012 at P 576 (2013).
[21] Avera/McKenzie Direct at 56-61.

observer of stock market commentary and the investment media quickly comes to the realization that investors' choices are almost limitless. It is simple, common sense 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 underpinning 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.[22] 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 total capital invested in utility stocks is only the tip of the iceberg of total common stock investment. Consistent with this view, Mr. Baudino noted (pp. 13-14) that the notion of "opportunity cost" underlies the Supreme Court's economic standards, and that:

> One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. … That alternative could have been another utility stock, a utility bond, <u>a mutual fund</u>, a money market fund, <u>or any other number of investment vehicles</u>.[23]

As Mr. Baudino correctly observed, "The key determinant in deciding whether to invest, however, is based on comparative levels of risk," and he concluded, "[T]he 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."[24] In other words, Mr. Baudino recognized that investors gauge their required returns from utilities against those available from non-utility firms of comparable risk. Our reference to a

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[22] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[23] Baudino Direct at 13-14 (emphasis added).
[24] Baudino Direct at 14.

comparable-risk Non-Utility Group is entirely consistent with the guidance of the Supreme Court and the principles outlined in Mr. Baudino's own testimony.

Q21. DOES DR. WOOLRIDGE APPARENTLY CONSIDER NON-UTILITY STOCK RETURNS RELEVANT TO DETERMINING THE COST OF CAPITAL?

A21. Yes, he does. Dr. Woolridge cites many studies of past and expected stock market returns in his testimony, including a list of over 30 studies included on Exhibit JRW-11. *Not one* of these studies is limited to utilities, and all include a predominance of non-utility common stocks, *e.g.*, the S&P 500 Index. Moreover, while Dr. Woolridge references a study of industry betas done at New York University that suggests utilities have lower risks than the average firm in the non-regulated sector,[25] this establishes nothing more than the obvious – while some unregulated firms have higher risks than utilities, others have lower risks. As documented in our direct testimony and discussed further in our rebuttal testimony, the firms in our Non-Utility Group are also in the lower range of risk as measured by objective, widely referenced benchmarks.

Q22. DID MR. BAUDINO OR DR. WOOLRIDGE PRESENT ANY OBJECTIVE EVIDENCE TO SUPPORT THEIR CONTENTION THAT YOUR NON-UTILITY PROXY GROUP IS RISKIER THAN THE COMPANIES OR YOUR COMBINATION UTILITY GROUP?

A22. No. Dr. Woolridge presented no meaningful evidence to rebut the results for our Non-Utility Group; rather, he simply observed that the "lines of business are vastly different" from utilities and they do not operate in a "highly regulated environment."[26] Similarly, apart from sweeping generalizations about the risk

[25] Woolridge Direct at 29.
[26] *Id.* at 81.

differences between regulated and non-regulated companies, Mr. Baudino provided no support whatsoever for his contention that our Non-Utility Group is riskier than the Companies or the proxy groups of utilities. Both Dr. Woolridge and Mr. Baudino ignored any comparison of accepted measures of investment risks, and instead simply noted that there are distinctions in the operating circumstances and degree of regulation between utilities and firms in the competitive sector.

Our direct testimony did not contend that the operations of the companies in the Non-Utility Group are comparable to those of utilities. Clearly, operating a worldwide enterprise in the beverage, pharmaceutical, retail, or food industry involves unique circumstances that are as distinct from one another as they are from an electric utility. But as the Supreme Court recognized, investors consider the expected returns available from all these opportunities in evaluating where to commit their scarce capital. So long as the risks associated with the Non-Utility Group are comparable to the Companies and other utilities – and our direct testimony demonstrates conclusively that they are lower – the resulting DCF estimates provide a meaningful benchmark for the cost of equity.

Consider Mr. Baudino's 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."[27] Based on this, Mr. Baudino summarily concluded, "Obviously, the non-utility companies have higher overall risk structures." In fact, however, investors are quite aware that utilities are not guaranteed recovery of reasonable and necessary costs incurred to 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-

[27] Baudino Direct at 47.

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.

Q23. DOES OBJECTIVE EVIDENCE SUPPORT THE RISK ARGUMENTS OF DR. WOOLRIDGE OR MR. BAUDINO?

A23. No. In fact, the objective risk measures specifically cited by these witnesses as being relevant indicia of overall investment risks contradict their assertions. It is telling to recognize that Dr. Woolridge (at Exhibit JRW-4) acknowledged the relevance of the objective risk measure afforded by published credit ratings in evaluating his proxy group. Similarly, Mr. Baudino testified that bond ratings reflect a detailed and comprehensive analysis of the key factors contributing to a firm's overall investment risk, concluding (p. 15), "Bond and credit ratings are tools that investors use to assess the risk comparability of firms."

Contradicting Mr. Baudino's unsupported assertion (p. 47) that the companies in our Non-Utility Group "have higher overall risk structures," our direct testimony noted that the average corporate credit rating for the Non-Utility Group of "A" is higher than the "BBB+" average for the Utility Group and the BBB rating assigned to the Companies.[28] This assessment is confirmed by the review of beta values and other objective indicators of investment risk presented in Table 6 to our direct testimony, which consider the impact of competition and market share, 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.

Q24. DOES THE FACT THAT UTILITIES ARE REGULATED SOMEHOW INVALIDATE THIS COMPARISON OF OBJECTIVE RISK INDICATORS?

A24. Absolutely not. While we do not disagree that utilities operate under a regulatory regime that differs from firms in the competitive sector, any risk-reducing benefit of

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[28] Avera/McKenzie Direct at Table 6. P. 58.

regulation is already incorporated in the overall indicators of investment risk presented in Table 6 to our direct testimony. The impact of regulation on a utility's investment risks is one of the key elements considered by credit rating agencies and investment advisory services, such as S&P and Value Line, when establishing corporate credit ratings and other risk measures. As a result, the impact of regulatory protections is already reflected in our risk analysis. Meanwhile, the beta values supported by modern financial theory are premised on stock price volatility relative to the market as a whole, and are not dependent on an assessment of firm-specific considerations. As a result, the impact of regulatory differences on investment risk is accounted for in the published risk indicators relied on by investors and cited in our direct testimony.

Q25. WHAT DO THESE BENCHMARKS YOU DISCUSS IMPLY WITH RESPECT TO OAG'S AND KIUC'S RECOMMENDATIONS?

A25. As set forth above, objective consideration of regulatory standards and alternative benchmarks demonstrate that the 8.75% and 8.60% ROEs recommended by Dr. Woolridge and Mr. Baudino are too low and violate the economic and regulatory standards underlying a fair ROE.

III. DCF RESULTS ARE UNDERSTATED

Q26. WHAT ARE THE FUNDAMENTAL PROBLEMS WITH THE DCF ANALYSES CONDUCTED BY DR. WOOLRIDGE?

A26. There are numerous fundamental problems with the DCF analyses presented by Dr. Woolridge that lead to biased end results:

- Reliance on dividend growth rates and historical growth measures do not reflect a meaningful guide to investors' expectations;
- Dr. Woolridge discounts reliance on analysts' growth forecasts for earnings per share ("EPS") as somehow biased, and fails to recognize that it is investors' *perceptions and expectations* that must be considered in applying the DCF model;

- Rather than looking to the capital markets for guidance as to investors' forward-looking expectations, Dr. Woolridge applies the DCF model based on his own personal views; and,
- Because Dr. Woolridge failed to test the reasonableness of model inputs, he incorrectly includes data that results in illogical cost of equity estimates.

As a result of these flaws and omissions, the resulting DCF cost of equity estimates are downward biased and fail to reflect investors' required rate of return.

Q27. DO THE GROWTH RATES REFERENCED BY DR. WOOLRIDGE MIRROR INVESTORS' LONG-TERM EXPECTATIONS IN THE CAPITAL MARKETS?

A27. No. There is every indication that his growth rates, and resulting DCF cost of equity estimates, are biased downward and fail to reflect investors' required rate of return. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining growth in dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the utility industry or the expectations that investors have incorporated into current market prices.

Q28. DID DR. WOOLRIDGE AND MR. BAUDINO RECOGNIZE THE PITFALLS ASSOCIATED WITH HISTORICAL GROWTH RATES?

A28. Yes. Dr. Woolridge noted that:

> [T]o best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.[29]

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[29] Woolridge Direct at 38.

But as he acknowledged, historical growth rates can differ significantly from the forward-looking growth rate required by the DCF model:

> [O]ne must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles).[30]

Similarly, Mr. Baudino noted (p. 21) that the analysis of investors' cost of equity "is a forward-looking process," and that "historical growth rates may not accurately represent investors' expectations." Mr. Baudino concluded that analysts' forecasts "provide better proxies for the expected growth components in the DCF model than historical growth rates." Moreover, to the extent historical trends for utilities are meaningful, they are already captured in projected growth rates, including those published by Value Line, IBES, Zacks, and Reuters, since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends.

Q29. DR. WOOLRIDGE ARGUES (P. 40) THAT, "THE APPROPRIATE GROWTH RATE IN THE DCF MODEL IS THE DIVIDEND GROWTH RATE." DO YOU AGREE THAT THIS IS WHAT INVESTORS ARE MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A29. No. Implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of actual investors. In the case of utilities, growth rates in dividends per share ("DPS") are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly

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[30] *Id*. at 37-38.

altered their dividend policies in response to more accentuated business risks in the industry.[31] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has lagged as utilities conserve financial resources to provide a hedge against heightened uncertainties.

Q30. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A30. As payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from DPS to earnings as a measure of long-term growth. Future trends in EPS, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. As noted in our direct testimony, the importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community and by other regulators.[32] 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].[33]

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 earnings forecasts attests to their relative influence. The fact that securities analysts focus on growth EPS, and that DPS growth rates are not routinely published, indicates that projected EPS growth rates

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[31] For example, the payout ratio for electric utilities fell from approximately 80% historically to on the order of 60%. *See, e.g.*, The Value Line Investment Survey (Sep. 15, 1995 at 161, Feb. 24, 2012 at 136).

[32] Avera/McKenzie Direct at 30-34.

[33] Morin, Roger , "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006).

are likely to provide a superior indicator of the future long-term growth expected by investors.

Q31. IS DR. WOOLRIDGE CONSISTENT IN HIS INSISTENCE THAT HISTORICAL GROWTH RATES AND TRENDS IN DPS MUST BE CONSIDERED IN APPLYING THE DCF MODEL?

A31. No. In his testimony before FERC, Dr. Woolridge has applied the DCF model without any reference to historical trends or growth rates in DPS.[34] Despite his fervent indictment of analysts' EPS growth projections, this data largely serves as the basis for his own DCF analysis.[35]

Q32. SHOULD THE KPSC GIVE ANY CREDENCE TO DR. WOOLRIDGE'S ALLEGATIONS THAT PROJECTED EPS GROWTH RATES ARE BIASED?

A32. No. These arguments were addressed on pages 32-34 of our direct testimony. In applying the DCF model to estimate the cost of equity, the <u>only</u> relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Dr. Woolridge's claim that analysts' estimates are discounted by investors is illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, it would be irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications implies that investors use them as a basis for their expectations.

The continued success of investment services such as IBES and Value Line, and the fact that projected growth rates from such sources are widely referenced,

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[34] *See, e.g.*, *Testimony of J. Randall Woolridge*, Docket No. EL11-66-000, Exhibit SC-100.

[35] Dr. Woolridge noted (p. 44) that his analysis gives "primary weight" to securities analysts' projected growth measures.

provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As the KPSC has previously concluded:

> KU's argument concerning the appropriateness of using investors' expectations in performing a DCF analysis is more persuasive than the AG's argument that analysts' projections should be rejected in favor of historical results. The Commission agrees that analysts' projections of growth will be relatively more compelling in forming investors' forward-looking expectations than relying on historical performance…[36]

Similarly, Mr. Baudino noted that analysts' projected EPS growth rates "are widely available to investors and one can reasonably assume that they influence investor expectations," and he concluded that analysts' forecasts "provide better proxies for the expected growth component in the DCF model."[37]

Q33. DID DR. WOOLRIDGE PROVIDE ANY MEANINGFUL SUPPORT FOR HIS ALLEGATION THAT VALUE LINE FORECASTS ARE "EXCESSIVE" AND "UNREALISTIC"?

A33. No. Dr. Woolridge based this assertion on his personal belief that Value Line does not report a sufficient number of negative growth rates.[38] But negative growth rates imply a cost of equity less than the utility's dividend yield, and are inconsistent with the assumptions of the DCF model and not likely to be representative of investors' expectations. Dr. Woolridge's personal opinions are irrelevant to a determination of what investors expect and, contrary to his conclusion, Value Line is a well-recognized source in the investment and regulatory communities. For example,

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[36] *Case No. 2009-00548*, Final Order at 30-31.
[37] Baudino Direct at 21.
[38] Woolridge Direct at B-13.

Cost of Capital – A Practitioners' Guide, published by the Society of Utility and Financial Analysts, noted that:

> [A] number of studies have commented on the relative accuracy of various analysts' forecasts. Brown and Rozeff (1978) found that Value Line was superior to other forecasts. Chatfield, Hein and Moyer (1990, 438) found, further "Value Line to be more accurate than alternative forecasting methods" and that "investors place the greatest weight on the forecasts provided by Value Line."[39]

Similarly, Mr. Baudino noted that Value Line "is a widely used and respected source of investor information."[40] Given the fact that Value Line is perhaps the most widely available source of information on common stocks, the projections of Value Line analysts provide an important guide to investors' expectations. Moreover, in contrast to Dr. Woolridge's unsupported assertion, the fact that Value Line is not engaged in investment banking or other relationships with the companies that it follows reinforces its impartiality in the minds of investors.

Q34. IS THE DOWNWARD BIAS IN DR. WOOLRIDGE'S HISTORICAL AND DPS GROWTH MEASURES SELF EVIDENT?

A34. Yes, it is. As shown on page 3 of Exhibit JRW-10, many of the individual historical growth rates reported by Dr. Woolridge for the companies in his electric proxy group were *negative*, which provides absolutely no meaningful information regarding investors' expectations.

Similarly, over one-half of Dr. Woolridge's historical DPS growth rates are 1.0% or less. Combining a growth rate of 1.0% with Dr. Woolridge's dividend yield of 3.5% (Exhibit JRW-10, p. 1) implies a DCF cost of equity of approximately

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[39] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at 8-28.
[40] Baudino Direct at 20.

4.5%. This implied cost of equity falls below the yield from triple-B public utility bonds, which averaged approximately 4.6% over the six-months ended February 2015.[41] Clearly, the risks associated with an investment in public utility common stocks exceed those of long-term bonds and Dr. Woolridge's historical DPS growth measures provide no meaningful information regarding the expectations and requirements of investors. Meanwhile, projected DPS growth rates included in Dr. Woolridge's analysis ranged from -3.5% to 12.0%. When combined with Dr. Woolridge's 3.5% dividend yield the implied cost of equity range based on these values is 0.0% to 15.5%, which again gives no useful basis to evaluate a fair ROE for the Companies.

Q35. DID DR. WOOLRIDGE MAKE ANY EFFORT TO TEST THE REASONABLENESS OF THE INDIVIDUAL GROWTH ESTIMATES HE RELIED ON TO APPLY THE CONSTANT GROWTH DCF MODEL?

A35. No. Despite recognizing that caution is warranted in using historical growth rates, Dr. Woolridge simply calculated the average and median of the individual growth rates with no consideration for the reasonableness of the underlying data. In fact, as demonstrated above, many of the cost of equity estimates implied by Dr. Woolridge's DCF application make no economic sense.

Q36. DOES REFERENCE TO THE MEDIAN CORRECT FOR ANY UNDERLYING BIAS IN UNDERLYING GROWTH RATES?

A36. No. While Dr. Woolridge (p. 44) and Mr. Baudino (p. 40) advance the median as being "more accurate,"[42] 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. Reliance on the

[41] Moody's Analytics, Yields & Spreads Data, http://credittrends.moodys.com/chartroom.asp?c=3.
[42] Baudino Direct at 26.

median value for a series of illogical values does not correct for the inability of individual cost of equity estimates to pass fundamental tests of economic logic.

Q37. WHAT APPROACH SHOULD DR. WOOLRIDGE AND MR. BAUDINO HAVE USED TO EVALUATE LOW-END DCF ESTIMATES?

A37. The ROE that investors require from a utility's common stock, which is the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, Dr. Woolridge and Mr. Baudino should have eliminated growth rates that produce illogical DCF results.

Q38. HAVE OTHER REGULATORS RECOGNIZED THAT IT IS APPROPRIATE TO ADD A RISK PREMIUM ABOVE THE COST OF DEBT WHEN EVALUATING LOW-END DCF VALUES?

A38. Yes. The practice of eliminating low-end outliers has been affirmed in numerous FERC proceedings.[43] In *Southern California Edison* FERC noted that adjustments to the zone of reasonableness are justified where applications of its preferred DCF approach produce illogical results:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[44]

Similarly, in its October 2006 decision in *Kern River Gas Transmission Company*, FERC noted that:

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[43] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008).
[44] *Southern California Edison Company*, *Edison* at 61,266 (footnote omitted).

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[45]

FERC upheld the opinion of FERC Staff and the Administrative Law Judge ("ALJ") that cost of equity estimates for these two proxy group companies "were too low to be credible."[46]

More recently, in Opinion No. 531 FERC concluded that, "The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt."[47] Monthly yields on triple-B bonds reported by Moody's averaged approximately 4.6% over the six months ended February 2015,[48] and FERC has used 100 basis points above this benchmark as an approximation of this threshold, but has also recognized that this is a flexible test.[49]

Q39. HAS DR. WOOLRIDGE ADOPTED THIS EXACT SAME TEST OF LOW-END DCF ESTIMATES IN OTHER FORUMS?

A39. Yes. For example, in prior testimony filed with FERC Dr. Woolridge applied this test to the results of his DCF analysis.[50] As Dr. Woolridge concluded:

> These data suggest that the prospective yield on utility bonds with a rating similar to the proxy group (A-/BBB+) is in the 5.0% range. Given this figure, and FERC's bond yield plus 100 basis point threshold for the low-end outliers, the elimination [of] the low-end results for Entergy (5.6%) and Great Plains Energy (6.2%) is supported.[51]

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[45] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 (2006) at P 140 and footnote 227.
[46] *Id.*
[47] Opinion No. 531 at P 122.
[48] Moody's Investors Service, http://credittrends.moodys.com/chartroom.asp?c=3.
[49] *Id.*
[50] *Direct Testimony of J. Randall Woolridge,* FERC Docket No. EL11-66.
[51] *Id.* at 35-36.

Q40. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A40. As indicated in our direct testimony, while utility bond yields have declined substantially as the financial crisis has abated, it is generally expected that long-term interest rates will rise as the economy returns to a more normal pattern of growth. As shown in Table R-1 below, the most recent forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 6.84% over the period 2015-2019:

TABLE R-1
IMPLIED UTILITY BOND YIELDS

	2015-19
Projected AA Utility Yield	
IHS Global Insight (a)	6.10%
EIA (b)	6.08%
Average	6.09%
Current A - AA Yield Spread (c)	0.06%
Implied Single-A Utility Yield	**6.15%**
Current BBB - AA Yield Spread (c)	0.75%
Implied Triple-B Utility Yield	**6.84%**

(a) IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014)
(b) Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Sep. 2014 - Feb. 2015

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb over 200 basis points through 2019.[52]

[52] *Blue Chip Financial Forecasts*, Vol. 33, No. 12 (Dec. 1, 2014).

Q41. WHAT ARE THE IMPLICATIONS OF DR. WOOLRIDGE'S AND MR. BAUDINO'S FAILURE TO ELIMINATE ILLOGICAL DATA IN APPLYING THE DCF MODEL?

A41. The DCF results presented by Dr. Woolridge and Mr. Baudino are unreliable, downward biased, and should be given no weight.

Q42. IS THERE ANY BASIS TO EXCLUDE A SYMMETRICAL NUMBER OF ESTIMATES ON THE LOW AND HIGH END, AS DR. WOOLRIDGE CONTENDS (PP. 61-62)?

A42. No. As discussed above, low-end outliers were evaluated 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 range of results, and there is no basis to discard an equal number of values from the top of the range. While the upper end cost of equity estimate of 13.1% percent from our Exhibit No. 5 may exceed expectations for most utilities, the remaining low-end estimates in the 7.6% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, the values at the upper end of our DCF range provide a reasonable basis on which to evaluate investors' required rate of return.

Q43. DOES MR. BAUDINO'S REFERENCE TO ALLOWED ROEs PROVIDE A LOGICAL BASIS TO EVALUATE HIGH-END DCF ESTIMATES?

A43. No. Mr. Baudino suggests (pp. 38-39) that any DCF value that exceeds the average ROE allowed by state regulators is inherently suspect and should be disregarded. Of course, following Mr. Baudino's flawed logic, it would be just as valid to argue for the elimination of all values *below* the average allowed ROE. While the allowed ROEs referenced by Mr. Baudino certainly call into question the validity of his own 8.6% ROE recommendation, they provide no basis to evaluate the range of plausible

DCF results. The Supreme Court has recognized that there is broad latitude in establishing reasonable ROE range:

> Statutory reasonableness is an abstract quality represented by an area rather than a pinpoint. *It allows a substantial spread between what is unreasonable because too low and what is unreasonable because too high.*[53]

In contrast to the "pinpoint" test proposed by Mr. Baudino, our DCF results are entirely consistent with this standard, and provide a sound basis to evaluate a fair ROE for the Companies.

Q44. DR. WOOLRIDGE AND MR. BAUDINO ALSO PRESENTED SUSTAINABLE, "BR" GROWTH RATES (EX. JRW-10, P. 4; EX. NO. RAB-5, P. 1). SHOULD THE KPSC PLACE ANY WEIGHT ON THESE VALUES?

A44. No. The internal growth rates calculated by Dr. Woolridge and Mr. Baudino are downward biased because of computational errors and omissions. These witnesses based their calculations of the internal, "br" retention growth rate on data from Value Line, which reports end-of-period results. If the rate of return, or "r" component of the internal growth rate, is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year. This downward bias has been recognized by FERC,[54] which specifically requires an adjustment to Value Line data to correct for the bias introduced by calculating "r" using end-of-year data.[55] Dr. Woolridge has also recognized and adopted this adjustment to Value Line's projections:

> The average values for r are then adjusted by the 'Adjustment Factor' since Value Line's expected earned rate of return on equity is based

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[53] *Montana-Dakota Utils. Co. v. Nw. Pub. Serv. Co.*, 341 U.S. 246, 251 (1951) (emphasis added).

[54] *See, e.g., Southern California Edison Company*, Opinion No. 445 (Jul. 26, 2000), 92 FERC ¶ 61,070.

[55] *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265 (2008).

on end-of-year figure equity. The Adjustment Factor is calculated as ((2*(1+5-yr Change in Equity)/(2+5-yr Change in Equity)).[56]

Because Dr. Woolridge and Mr. Baudino both ignored this adjustment in this case, their internal, "br" growth rates are distorted and should be ignored.

Q45. WHAT OTHER CONSIDERATION LEADS TO A DOWNWARD BIAS IN THE INTERNAL, "BR" GROWTH RATES OF DR. WOOLRIDGE AND MR. BAUDINO?

A45. Both Dr. Woolridge and Mr. Baudino ignored the impact of additional issuances of common stock in their analyses of the sustainable growth rate. Under DCF theory, the "sv" factor is a component designed to capture the impact on growth of issuing new common stock at a price above, or below, book value. Professor Myron J. Gordon recognized the need for the "sv" adjustment in his 1974 study,[57] and Dr. Woolridge has also included the additional growth from new share issues by incorporating the "sv" component in prior testimony before FERC.[58] The fact that Dr. Woolridge and Mr. Baudino failed to consider the incremental impact of new share issues on growth results in another downward bias to their "internal" growth rates, which should be given no weight.

Q46. WHAT DO YOU CONCLUDE BASED ON YOUR REVIEW OF THE DCF ANALYSES PRESENTED BY DR. WOOLRIDGE AND MR. BAUDINO?

A46. Historical growth rates and trends in DPS are distorted by fundamental changes in industry financial policies and Dr. Woolridge and Mr. Baudino failed to evaluate the underlying reasonableness of individual growth rates. In addition, the calculations used to arrive at the internal growth rates reported by Dr. Woolridge and Mr.

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[56] *Direct Testimony of Randall J. Woolridge,* Federal Energy Regulatory Commission, Docket No. EL-11-66 (Oct. 1, 2012).

[57] Gordon, Myron J., "The Cost of Capital to a Public Utility," MSU Public Utilities Studies (1974), at 31–32.

[58] *Testimony of J. Randall Woolridge*, FERC Docket No. EL-66 at Exhibit JRW-8, pp. 3-4 (2011) and Exhibit SC-111 (2012).

Baudino are flawed and incomplete. As a result, their DCF cost of equity estimates are biased downward and fail to reflect investors' required rate of return.

IV. CAPM RESULTS SHOULD BE DISREGARDED

Q47. DID EITHER DR. WOOLRIDGE OR MR. BAUDINO RELY ON THEIR CAPM RESULTS IN ARRIVING AT THEIR RECOMMENDATIONS IN THIS CASE?

A47. No. Dr. Woolridge ignored his 7.9% CAPM cost of equity estimate in arriving at his 8.75% recommendation, which is near the top of his 7.8% to 8.8% cost of equity range. Dr. Woolridge noted that he relied primarily on the DCF model, and he concluded that the CAPM provides "a less reliable indication of equity cost rates for public utilities."[59] Similarly, Mr. Baudino noted (p. 3) that his ROE recommendation was based solely on cost of equity estimates implied by his application of the DCF model and ignored his CAPM results entirely. While we agree with the decision of Dr. Woolridge and Mr. Baudino to give no weight to their CAPM results, for completeness our rebuttal testimony nevertheless addresses the major flaws associated with their applications of this approach.

Q48. WHAT IS THE FUNDAMENTAL PROBLEM ASSOCIATED WITH THE HISTORICAL APPROACHES USED BY DR. WOOLRIDGE AND MR. BAUDINO TO APPLYING THE CAPM?

A48. Like the DCF model, the CAPM is an *ex-ante*, or forward-looking model based on expectations of the future. As a result, in order 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. Dr. Woolridge recognized that "ex post returns are not the same as ex ante expectations" and noted that "market

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[59] Woolridge Direct at 31.

risk premiums can change over time; increasing when investors become more risk-averse."[60] Similarly, Mr. Baudino has recognized that, "There is no real support for the proposition that an unchanging, mechanically applied historical risk premium is representative of current investor expectations and return requirements."[61]

Nevertheless, Dr. Woolridge's application of the CAPM method was based entirely on *historical* – not projected – rates of return, as was the CAPM method presented on Mr. Baudino's Exhibit (RAB-7). The key importance of current expectations was recognized by *Morningstar*, one of the sources relied on by Dr. Woolridge and Mr. Baudino:

> 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, the expectations of future events are the only factors that actually determine cost of capital.[62]

Because the backward-looking analyses of Dr. Woolridge and Mr. Baudino ignore the returns investors are currently requiring in the capital markets, the resulting CAPM estimates fall woefully short of investors' current required rate of return.

Q49. DR. WOOLRIDGE (P. 54-55) ATTEMPTS TO CHARACTERIZE HIS CAPM STUDY AS INCORPORATING AN "*EX ANTE*" RISK PREMIUM. IS THIS AN ACCURATE ASSESSMENT?

A49. No. In order to be considered a forward-looking, *ex ante* estimate of the current market risk premium, the analysis must be predicated on investors' current expectations. Dr. Woolridge did not attempt to develop a market risk premium using current capital market information. Rather, he simply presented the results of

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[60] Woolridge Direct at 45.

[61] *Direct Testimony and Exhibits of Richard A. Baudino*, Case No. 2012-00221 & Case No. 2012-00222, at p. 28 (October 2012).

[62] Morningstar, *Ibbotson SBBI, 2012 Valuation Yearbook* at 21 (2012).

various studies and surveys conducted in the past. Certain of these studies may have attempted to infer the equity risk premium using expected data at the time they were developed, but expectations at some point in the past are not equivalent to investors *ex ante* requirements in capital markets today.

In other words, instead of directly considering requirements in today's capital markets, Dr. Woolridge is implicitly asserting that events and expectations for the time periods covered by selected historical studies is more representative of what is likely to occur going forward. This assertion runs counter to the assumptions underlying the use of the CAPM approach to estimate investors' required return, which is purely a forward-looking model. Indeed, Dr. Woolridge granted that, "The use of historical returns as market expectations has been criticized in numerous academic studies," and he concluded that, "(1) ex post returns are not the same as ex ante expectations; (2) market risk premiums can change over time, increasing when investors become more risk-averse and decreasing when investors become less risk-averse; and (3) market conditions can change such that ex post historical returns are poor estimates of ex ante expectations."[63]

In short, the only relevant issue in applying the CAPM method is determining the return investors currently expect to earn on money invested today. In contrast to the historical approaches relied on by Dr. Woolridge and Mr. Baudino, our method represents a straightforward and direct approach to answer this question that has been recognized as superior to historical methods by other regulators.[64]

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[63] Woolridge Direct at 50-51.
[64] Opinion No. 531-B at PP 108-119.

Q50. IS THERE EVIDENCE THAT THE STUDIES REFERENCED BY DR. WOOLRIDGE DO NOT REFLECT INVESTORS' EXPECTATIONS?

A50. Yes. The vast majority of the equity risk premium findings reported by Dr. Woolridge do not make economic sense and contradict his own testimony. For example, page 5 of Dr. Woolridge's Exhibit JRW-11 reveals that over one-half of the historical studies included in Dr. Woolridge's review found market equity risk premiums of approximately 5.0% or below.[65] This was also true for over one-half of the individual risk premium studies that Dr. Woolridge classified as "more recently."[66] But combining a market equity risk premium of 5.0% with Dr. Woolridge's 4.0% risk-free rate results in an indicated cost of equity for the <u>market as a whole</u> of 9.0%, which barely exceeds Dr. Woolridge's ROE recommendations for the Companies in this case. Many of his other benchmarks for the market rate of return fall *below* the anemic cost of equity he recommends for the Companies. For example, Dr. Woolridge develops a <u>market</u> rate of return of 7.25% based on his "building blocks" approach,[67] which falls 150 basis points *below* his recommended ROE in this case.

Meanwhile, after noting that beta is the only relevant measure of investment risk under modern capital market theory, Dr. Woolridge concluded that his comparison of beta values (Exhibit JRW-8) indicates that investors' required return on the market as a whole should exceed the cost of equity for electric utilities.[68] Based on Dr. Woolridge's own logic, it follows that a market rate of return that does not exceed his own downward biased ROE recommendation by a significant margin has no relation to the current expectations of real-world investors. The fact that

[65] Similarly, Dr. Woolridge reported equity risk premiums of 4.9%, 1.88%, and 5.0% (pp. 54-55) based on selected surveys.
[66] Exhibit JRW-11, p. 6.
[67] Woolridge Direct at C-4.
[68] *Id.* at 29.

much of his CAPM "evidence" violates the risk-return tradeoff that is fundamental to finance clearly illustrates the frailty of Dr. Woolridge's analyses.

Q51. ARE YOU IN ANY WAY ALLEGING THAT ALL THESE STUDIES AND SURVEYS ARE INCORRECT?

A51. No, not at all. Rather, we are challenging the inferences that Dr. Woolridge draws from them, and the particular use being made of the cited studies. The point that we are making is that there is more than one way to define and calculate an equity risk premium. The problem with Dr. Woolridge's approach is that, instead of looking directly at an equity risk premium based on current expectations – which is what is required in order to properly apply the CAPM – he undertakes an unrelated exercise of compiling a list of selected computations culled from the historical record. Average realized risk premiums computed over some selected time period may be an accurate representation of what was actually earned in the past, but they don't answer the question as to what risk premium investors were actually expecting to earn on a forward-looking basis during these same time periods. Similarly, calculations of the equity risk premium developed at a point in history – whether based on actual returns in prior periods or contemporaneous projections – are not the same as the forward-looking expectations of today's investors, which are premised on an entirely different set of capital market and economic expectations.

Likewise, surveys of selected corporate executives or economists, or building blocks based on academic research, are not equivalent to investors' required returns in the coming period. Since the benchmark for a fair ROE requires that the utility be able to compete for capital in the current capital market, the relevant inquiry is to determine the return that real world investors in today's markets require from the Companies in order to compete for capital with other comparable risk alternatives. In short, while there are many potential definitions of the equity risk premium, the only relevant issue for application of the CAPM in a regulatory context is the return investors currently expect to earn on money invested today in the risky market portfolio versus the risk-free U.S. Treasury alternative.

Q52. WERE DR. WOOLRIDGE OR MR. BAUDINO JUSTIFIED IN RELYING ON GEOMETRIC MEANS AS A MEASURE OF AVERAGE RATE OF RETURN WHEN APPLYING THE HISTORICAL CAPM?

A52. No. While both the arithmetic and geometric means are legitimate measures of average return, they provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The arithmetic mean measures what the expected return would have to be each period to achieve the realized change in value over time.

In estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. When referencing realized rates of return in the past, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods. *Regulatory Finance: Utilities' Cost of Capital* had this to say:

> One major issue relating to the use of realized returns is whether to use the ordinary average (arithmetic mean) or the geometric mean return. *Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital.* When using historical risk premiums as a surrogate for the expected market risk premium, the

> relevant measure of the historical risk premium is the arithmetic average of annual risk premiums over a long period of time.[69]

Similarly, Morningstar concluded that:

> For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. … The geometric average is more appropriate for reporting past performance, since it represents the compound average return.[70]

We certainly agree that both geometric and arithmetic means are useful, but the issue is not whether both measures can be useful; it is which one best fits the use for a forward-looking CAPM in this case. One does not have to get deeply into finance theory to see why the arithmetic mean is more consistent with the facts of this case. The KPSC is not setting a constant return that the Companies are guaranteed to earn over a long period. Rather, the exercise is to set an expected return based on test year data. In the real world, the Companies' yearly return will be volatile, depending on a variety of economic and industry factors, and investors do not expect to earn the same return each year.

The usefulness of the arithmetic mean for making forward-looking estimates was confirmed in *Quantitative Investment Analysis* (2007), one of the textbooks included in the study curriculum for the Chartered Financial Analyst designation, which concluded that the arithmetic mean is the appropriate measure when calculating an expected equity risk premium in a forward-looking context.[71] Just as importantly, by relying directly on expectations and estimates of investors' required rate of return, as incorporated in the CAPM analysis presented in our direct

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[69] Morin, Roger , "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports* AT 275 (1994) (emphasis added).
[70] Morningstar, *Ibbotson SBBI 2011 Valuation Yearbook* at 56 (2011).
[71] DeFusco, Richard , Dennis W. McLeavey, Jerald E. Pinto, and David E. Runkle, *Quantitative Investment Analysis*, John Wiley & Sons, Inc. (2007) at 128.

testimony, there is no need to debate the merits of geometric versus arithmetic means, because neither is required to apply this forward-looking approach.

Q53. WHAT DOES THIS IMPLY WITH RESPECT TO DR. WOOLRIDGE'S AND MR. BAUDINO'S CAPM RESULTS?

A53. For a variable series, such as stock returns, the geometric average will always be less than the arithmetic average. Accordingly, reference to geometric average rates of return provides yet another element of built-in downward bias to the CAPM applications of Dr. Woolridge and Mr. Baudino.

Q54. WHAT ABOUT DR. WOOLRIDGE'S VIEW THAT YOUR FORWARD-LOOKING ESTIMATE OF THE MARKET RATE OF RETURN IS TOO HIGH?

A54. The use of forward-looking expectations in estimating the market risk premium is well accepted in the financial literature. For example, in "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts" [*Journal of Applied Finance*, Vol. 11 No. 1, 2001], Robert S. Harris and Felicia C. Marston employed the DCF model and earnings growth projections from IBES – just as we did in our direct testimony. Dr. Woolridge's criticisms of our forward-looking CAPM approach seem to hinge on the fact that this method produces an equity risk premium for the S&P 500 that is considerably higher than his historical benchmarks – the majority of which produce illogical results.

But estimating investors' required rate of return by reference to current, forward-looking data, as we have done, is entirely consistent with the theory underlying the CAPM methodology. Dr. Woolridge does not suggest that the CAPM model is "wrong" to focus on forward-looking projections instead of backward, historical results, nor does he claim that looking to the future, as we have done, is a misapplication of the CAPM. Instead, he simply believes that the result of applying the CAPM in a manner that is consistent with the underlying assumptions produces a result that he views as being too high. But the application of alternative methods is not a process of deviating from the underlying assumptions of the model until the results are consistent with those produced using an alternative approach.

Q55. HAVE OTHER REGULATORS RELIED ON A FORWARD-LOOKING CAPM APPROACH SIMILAR TO THE ONE PRESENTED IN YOUR DIRECT TESTIMONY?

A55. Yes. We based our CAPM approach on the methods used by the Staff at the Illinois Commerce Commission, whose witnesses have routinely relied on a forward-looking market rate of return estimate to apply the CAPM. For example, Illinois Staff witness Rochelle Langfeldt employed an expected market return based on an analysis analogous to the approach described in our direct testimony:

> Q. How was the expected rate of return on the market portfolio estimated?
>
> A. The expected rate of return on the market was estimated by conducting a DCF analysis on the firms composing the S&P 500 Index ("S&P 500"). … Firms not paying a dividend as of June 28, 2001, or for which neither Zacks nor IBES growth rates were available were eliminated from the analysis. The resulting company-specific estimates of the expected rate of return on common equity were then weighted using market value data from Salomon Smith Barney, Performance and Weights of the S&P 500: Second Quarter 2001. The estimated weighted averaged expected rate of return for the remaining 365 firms composing 78.31% of the market capitalization of the S&P 500 equals 15.31%.[72]

More recently, FERC rejected the historical CAPM approach relied on by Dr. Woolridge and Mr. Baudino and adopted the same size, adjusted, forward-looking

[72] Direct Testimony of Rochelle Langfeldt, Illinois Commerce Commission Docket No. 01-0423 at 23-24 (2001).

CAPM application that we have proposed in this proceeding.[73] In addition, FERC also dismissed Dr. Woolridge's arguments (pp. 69-70) that growth rates for firms in the market as a whole should somehow be limited to growth in the general economy.[74]

Q56. IS THERE ANY MERIT TO MR. BAUDINO'S ARGUMENT (P. 42) 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?

A56. No. As Mr. Baudino recognized (p. 15-16), 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 hampered for firms that do not pay common dividends. Accordingly, our DCF analysis of the market rate of return properly focused on the dividend paying firms included in the S&P 500.

Meanwhile, Mr. Baudino (p. 26) predicated his DCF analysis of the market rate of return on the companies followed by Value Line. Of these approximately 1,700 companies, approximately 600 do not pay common dividends. In other words, over one-third of the companies that underpin Mr. Baudino's DCF analysis do not have the data necessary to implement this approach. Further, many of these firms are relatively small and lack a meaningful operating history. As a result, there is also greater uncertainty associated with estimating the future growth expectations that are central to the application of the DCF method. Taken together, these factors impugn the reliability of Mr. Baudino's market risk premium and confirm our

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[73] *Opinion No. 531-B*, 150 FERC ¶ 61,165 at P 108-119 (2015).
[74] *Id.* at P 113.

decision to restrict our analysis to the established, dividend paying firms in the S&P 500.

Q57. WHAT OTHER PROBLEMS ARE ASSOCIATED WITH MR. BAUDINO'S MARKET RATE OF RETURN BASED ON VALUE LINE DATA?

A57. While expected growth in earnings is far more likely to be representative of investors' forward-looking expectations, Mr. Baudino nevertheless included book value growth rates in the DCF analysis he employed to estimate the expected market rate of return. This had the effect of understating the resulting CAPM cost of equity estimates. As shown on Exhibit No. 14, basing Mr. Baudino's DCF analysis solely on EPS growth rates, which served as the basis for his DCF study for utilities, resulted in an estimated CAPM cost of equity of 10.05%.

Q58. DID DR. WOOLRIDGE AND MR. BAUDINO FAIL TO CONSIDER OTHER IMPORTANT FACTORS IN EVALUATING THE CAPM?

A58. Yes. As noted in our direct testimony,[75] empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size. To account for this, *Morningstar* – a source relied on by Dr. Woolridge and Mr. Baudino – has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity.

Q59. DO THE ARGUMENTS ADVANCED BY DR. WOOLRIDGE AND MR. BAUDINO UNDERMINE THE NEED FOR THIS ADJUSTMENT?

A59. No. Mr. Baudino simply observes that the average beta associated with the lower size deciles examined by *Morningstar* is greater than the average his proxy group.[76] While we do not dispute the observation, it has no relevance whatsoever to the

[75] Avera/McKenzie Direct at 43-44.
[76] Baudino at 43.

implications of *Morningstar's* 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. While the size premiums reported by *Morningstar* 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 *Morningstar* to quantify the size premium, and firm size has important practical implications with respect to the risks faced by investors in the utility industry.

Similarly, Dr. Woolridge's arguments concerning the implications of "survivor bias" are equally misplaced.[77] The expected returns of failed companies that are in decline or go out of business are irrelevant to the question of whether or not the CAPM fully accounts for investors' risk perceptions when applied to companies included in broad market indices, such as those reflected in *Morningstar's* analysis. The companies in the proxy groups used by Dr. Woolridge and Mr. Baudino are not start-ups – they are seasoned utilities that have been publicly traded for many years, just like the listed companies in the *Morningstar* data base. The arguments relative to survivor bias may have been relevant to the studies in the 1980's and 1990's, but they do not take away from the solid empirical basis of the size adjustment reported by *Morningstar* that are all based on surviving companies.

Further, it is not necessary to use the historical market risk premium from *Morningstar* to correctly apply the size adjustment. *Morningstar's* size adjustment is based on empirical research using their return data and betas, and there is no reason the size differential could not be properly applied to a CAPM using forward-looking risk premiums, as we have done.

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[77] Woolridge Direct at 72.

Q60. DOES THIS SIZE ADJUSTMENT APPLY TO UTILITIES?

A60. Yes. For example, a study reported in *Public Utilities Fortnightly* noted that the betas of small companies do not fully account for the higher realized rates of return associated with small company stocks:

> The smaller deciles show returns not fully explainable by the CAPM. The difference in risk premium (realized versus CAPM) grows larger as one moves from the largest companies in decile 1 to the smallest in decile 10. The difference is especially pronounced for deciles 9 and 10, which contain the smallest companies. [78]

The study went on to conclude that a publicly traded utility with a market capitalization of $1.0 billion would require a small company premium of approximately 130 basis points above the rate of return for larger firms.

We acknowledge that 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.[79] 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.

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[78] Annin, Michael, "Equity and the Small-Stock Effect", Public Utilities Fortnightly (Oct. 15, 1995), at 43.

[79] Dr. Woolridge also recognized that beta is the only relevant risk measure within the context of the CAPM. Woolridge Direct at 29.

V. NO INCONSISTENCY IN RISK PREMIUM METHOD

Q61. PLEASE RESPOND TO DR. WOOLRIDGE'S COMMENTS REGARDING YOUR RISK PREMIUM ANALYSIS (PP. 75-76)?

A61. Dr. Woolridge has two criticisms of our risk premium analysis based on previously allowed ROEs for utilities. The first is that the "base yield" on public utility bonds to which we added the risk premium is somehow inflated. This is not accurate. The yield to maturity is a direct measure of investors' required return to compensate for the risks they associate with utility bonds, including credit risks. Aside from the fact that his contention is not accurate, it is irrelevant because similar public utility bond yields were used to calculate the risk premium; hence, the risk premium would be understated by a comparable and offsetting amount. In addition, Dr. Woolridge suggests that our application of the risk premium approach considered only projected bond yields, which is not accurate. Page 1 of Exhibit No. 8 to our direct testimony applies this approach using current yields.

Second, Dr. Woolridge argues that allowed ROEs do not reflect investors' expectations. But as he recognized, "Regulatory commissions evaluate capital market data is setting authorized ROEs."[80] While regulators certainly consider case-specific evidence in evaluating a fair ROE, Dr. Woolridge provides no evidence to support his assertion that allowed ROEs, on balance, are distorted or biased.

Third, Dr. Woolridge claims that because utility common stocks have been selling in excess of book value for many years, this means regulators have routinely authorized ROEs greater than what investors require. This criticism suggests that Dr. Woolridge has a low regard for regulators' ability to make informed judgments as to the ROE that is necessary to compensate investors fairly for the use of their

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[80] Woolridge Direct at 76.

capital, enable the utility to attract capital on reasonable terms, and maintain the utility's financial integrity. Moreover, as discussed earlier, establishing returns to produce a market-to-book ratio of 1.00 implies a capital loss to investors in utility common stocks, which is inconsistent with regulatory standards and the expectations underlying utility stock prices.

Q62. DOES MR. BAUDINO ADVANCE ANY CREDIBLE CRITICISM OF YOUR RISK PREMIUM APPROACH?

A62. No. Mr. Baudino's only observation is that the risk premium method is "imprecise."[81] Of course, this "criticism" 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. While the tautology of the DCF model boils this determination down to the familiar dividend yield and growth rate components, this masks 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" is unsubstantiated and directly contradicted by the recent findings of FERC, where risk premium results were used to establish an ROE from the upper end of the DCF range due to its finding that DCF results were skewed downwards.[82]

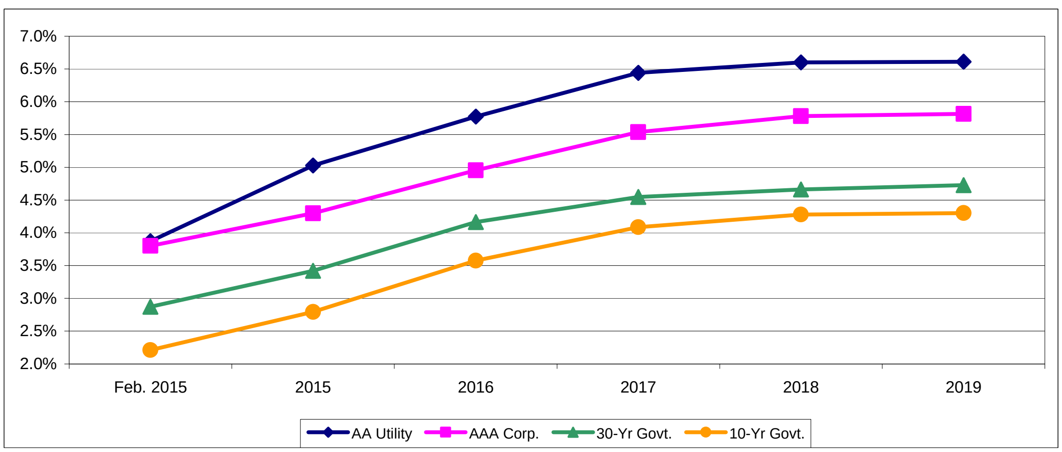
[81] Baudino Direct at 45
[82] Opinion No. 531.

VI. EXPECTED CAPITAL MARKET CONDITIONS

Q63. DR. WOOLRIDGE AND MR. BAUDINO ARGUE THAT CURRENT INTEREST RATES ARE INDICATIVE OF EXPECTATIONS FOR LOW CAPITAL COSTS. DO YOU AGREE?

A63. No. Investors' current outlook for long-term capital costs was discussed at length in our direct testimony.[83] None of the discussion presented by Dr. Woolridge or Mr. Baudino evidences a fundamental shift in expectations since that time. Figure R-1 below provides an updated comparison of current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from the Value Line Investment Survey ("Value Line"), IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the Energy Information Administration ("EIA"):

FIGURE R-1
INTEREST RATE TRENDS



Source:
Value Line Investment Survey, Forecast for the U.S. Economy (Feb. 20, 2015)
IHS Global Insight, The U.S. Economy: The 30-Year Focus (Third-Quarter 2014)
Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014)
Blue Chip Financial Forecasts, Vol. 33, No. 12 (Dec. 1, 2014)

Contrary to Dr. Woolrige's (p. 14) and Mr. Baudino's position (p. 9) that current interest rates are indicative of future expectations, these highly regarded and widely

[83] Avera/McKenzie Direct at 11-17.

referenced forecasts evidence a clear consensus in the investment community that the cost of long-term capital will be significantly higher over the 2015-2019 period.

Q64. PLEASE ADDRESS DR. WOOLRIDGE'S CONCERNS (P. 15) OVER THE ACCURACY OF INTEREST RATE FORECASTS.

A64. Dr. Woolridge apparently believes that because "100% of economists were wrong" in forecasting higher interest rates in 2014, investors will simply throw up their hands and give up attempts to anticipate the future. Of course, such a scenario is completely at odds with rational investor behavior, as evidenced by the intense scrutiny of Federal Reserve pronouncements for any nuanced clue as to future policy. The fact that independent forecasts of bond yields have not mirrored actual results is irrelevant. While the actual pattern of bond yields will invariably deviate from these forecasts, they provide an objective, well-recognized guidepost to investors' future expectations. Just as when relying on growth projections in applying the DCF model, the paramount consideration is investors' expectations, and not historical comparisons. The very same is true of investors' expectations for higher interest rates, and the fact that past forecasts have not materialized does not support Dr. Woolridge's subjective dismissal of this evidence.

VII. FLOTATION COSTS SHOULD BE CONSIDERED

Q65. PLEASE RESPOND TO DR. WOOLRIDGE'S SPECIFIC CRITICISMS OF YOUR FLOTATION COST ADJUSTMENT.

A65. First, while Dr. Woolridge suggests that flotation costs should be ignored because our adjustment was not predicated on a precise accounting for the Companies, this belies the point of the adjustment. LG&E and KU do not issue common stock, and will never incur flotation costs directly. The approach outlined in our direct testimony is supported by recognized regulatory textbooks and based on research reported in the academic literature, and the fact that the Companies do not incur issuance expenses directly provides no basis to ignore a flotation cost adjustment. Without a flotation adjustment, these legitimate costs of providing utility service will be excluded for ratemaking purposes and will undercut the Companies' ability to earn their authorized ROE.

Meanwhile, Dr. Woolridge mistakenly claims that a flotation cost adjustment "is necessary to prevent dilution of the existing shareholders."[84] In fact, a flotation cost adjustment is required in order to allow the utility the opportunity to recover the issuance costs associated with selling common stock. Dr. Woolridge's observation about the level of market-to-book ratios may be factually correct, but it has nothing to do with flotation costs. The fact that market prices may be above book value does not alter the fact that a portion of the capital contributed by equity investors is not available to earn a return because it is paid out as flotation costs. Even if the utility is not expected to issue additional common stock, a flotation cost adjustment is necessary to compensate for flotation costs incurred in connection with past issues of common stock.

Dr. Woolridge's argument (p. 78) that flotation costs are "not out-of-pocket expenses" is simply wrong. Dr. Woolridge apparently believes that if investors in past common stock issues had paid the full issuance price directly to the utility and the utility had then paid underwriters' fees by issuing a check to its investment bankers, that flotation cost would be a legitimate expense. Dr. Woolridge's observation merely highlights the absence of an accounting convention to properly accumulate and recover these legitimate and necessary costs. Just like the issuance costs associated with long-term bonds, which are recorded on the Companies' financial records and reflected in the embedded cost of debt, equity flotation costs

[84] Woolridge Direct at 77.

are a necessary expense associated with raising long-term capital, and should be considered in establishing a fair ROE.

With respect to Dr. Woolridge's (p. 79) and Mr. Baudino's (p. 46) contention that flotation costs are somehow accounted for in current stock prices, *Regulatory Finance: Utilities' Cost of Capital* has this to say:

> A third controversy centers around the argument that the omission of flotation cost is justified on the grounds that, in an efficient market, the stock price already reflects any accretion or dilution resulting from new issuances of securities and that a flotation cost adjustment results in a double counting effect. The simple fact of the matter is that whatever stock price is set by the market, the company issuing stock will always net an amount less than the stock price due to the presence of intermediation and flotation costs. As a result, the company must earn slightly more on its reduced rate base in order to produce a return equal to that required by shareholders.[85]

Similarly, the need to consider past flotation costs has been recognized in the financial literature, including sources that Dr. Woolridge relied on in his testimony. Specifically, Ibbotson Associates concluded that:

> Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital).[86]

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[85] Morin, Roger , "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.*at 174 (1994).
[86] Morningstar, *Ibbotson SBBI 2011 Valuation Yearbook* at 25 (2011).

VIII. PROXY GROUP REVENUE TEST IS UNSUPPORTED

Q66. DO YOU AGREE WITH DR. WOOLRIDGE AND MR. BAUDINO THAT THE SOURCE OF A UTILITY'S REVENUES IS A VALID CRITERION IN SELECTING A PROXY GROUP FOR THE COMPANIES?

A66. No. Dr. Woolridge and Mr. Baudino argued for the elimination of companies if less than 50% of total revenues were attributable to regulated electric utility operations.[87] However, both witnesses failed to demonstrate how this subjective criterion translates into differences in the investment risks perceived by investors. Any comparison of objective indicators demonstrates that investment risks for the firms in our proxy groups are relatively homogeneous and comparable to the Companies.

Q67. DID DR. WOOLRIDGE OR MR. BAUDINO DEMONSTRATE A NEXUS BETWEEN THEIR SUBJECTIVE REVENUE CRITERION AND OBJECTIVE MEASURES OF INVESTMENT RISK?

A67. No. Under the regulatory standards established by *Hope*[88] and *Bluefield*[89], the salient criterion in establishing a meaningful proxy group to estimate investors' required return is relative risk, not the source of the revenue stream. Dr. Woolridge Mr. Baudino presented no evidence to demonstrate a connection between the subjective revenue criterion that they employed and the views of real-world investors in the capital markets.

Due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as total revenues, between utility segments (*e.g.*, electric and natural gas) or regulated and non-regulated sources. As a result, even if one were to ignore the fact that there

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[87] Woolridge Direct at 17; Baudino Direct at 18.
[88] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[89] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

is no clear link between the source of a utility's revenues and investors' risk perceptions, it is generally not possible to accurately and consistently apply revenue-based criteria. In fact, other regulators have rebuffed these notions, with FERC rejecting attempts to restrict a proxy group to companies based on sources of revenues. As FERC concluded:

> This is inconsistent with Commission precedent in which we have rejected proposals to restrict proxy groups based on narrow company attributes.[90]

FERC has specifically rejected arguments that utilities "should be excluded from the proxy group given the risk factors associated with its unregulated, non-utility business operations."[91]

Q68. ARE THERE OTHER INCONSISTENCIES ASSOCIATED WITH THE REVENUE TESTS PROPOSED BY DR. WOOLRIDGE AND MR. BAUDINO?

A68. Yes. While Dr. Woolridge and Mr. Baudino screened all electric and combination electric and gas utilities followed by Value Line, their revenue tests were based solely on <u>electric</u> revenues and ignored the impact of gas utility operations. For example, despite the fact that Dr. Woolridge's source indicates that CenterPoint Energy (70%), DTE Energy (61%), Public Service Enterprise Group (63%), SCANA Corporation (74%), and Sempra Energy (74%) all have electric and gas utility revenues well in excess of 50% of consolidated revenues, Dr. Woolridge and Mr. Baudino would exclude these firms under their revenue test. Considering the similarities in the regulatory and business environments for regulated electric and gas utility operations, there is no justification for Dr. Woolridge's and Mr. Baudino's failure to incorporate gas utility revenues in implementing their revenue test.

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[90] *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 at P 118 (2008) (footnote omitted).
[91] *Bangor Hydro-Elec. Co.*, 117 FERC ¶ 61,129 at PP 19, 26 (2006).

The arbitrary nature of the 50% revenue criterion proposed by Dr. Woolridge and Mr. Baudino is further illustrated by the lack of any independent, objective findings to support his imposed threshold. In fact, Dr. Woolridge cannot seem to decide for himself what the correct cutoff should be. For example, in his 2010 testimony before the KPSC in Case No. 2009-00548, Dr. Woolridge argued to exclude companies with less than 80% of revenues attributable to electric operations. Dr. Woolridge's revenue statistic has no demonstrable link to risk and his internal inconsistency merely highlights the entirely subjective and baseless nature of his "test."

IX. REQUESTED CAPITAL STRUCTURE SHOULD BE APPROVED

Q69. WHAT WAS DR. WOOLRIDGE'S RATIONALE FOR REJECTING THE CAPITALIZATION REQUESTED BY THE COMPANIES?

A69. Dr. Woolridge's assertion that the Companies' capital structure should be rejected was based on his conclusion that the equity ratio implied by the Company's capitalization is higher than the average for his electric proxy group, and for the Companies' parent, PPL.[92]

Q70. DOES THIS PROVIDE A LOGICAL BASIS TO REJECT THE COMPANIES' ACTUAL CAPITALIZATION?

A70. No. As noted in our direct testimony,[93] while industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. While the degree of debt leverage is one consideration impacting investors' risk perceptions, it is not the whole picture. Overall investment risk, such as that reflected in bond ratings and other risk measures referenced by investors,

[92] Woolridge Direct at 22.
[93] Avera/McKenzie Direct at 21-23.

also considers the specific business risks underlying a utility's operations. The Companies' credit ratings, which Dr. Woolridge relied on to establish his proxy group, already reflect the combined impact of these business and financial risk exposures. Moreover, the Companies' equity ratio falls within the range of capitalizations maintained by the firms in the proxy groups that we and Dr. Woolridge relied on to estimate the cost of equity.

As discussed in our direct testimony, investors and bond rating agencies are increasingly focused on the importance of regulatory support. Making unwarranted adjustments to the capital structure or adopting an unreasonably low ROE would undoubtedly have a negative impact on investors' risk perceptions, and doing both would be outright alarming. Dr. Woolridge's proposed hypothetical capital structure amounts to nothing more than an ill-disguised attempt to engineer a lower overall rate of return by artificially substituting debt for equity.

Q71. WHAT CAPITALIZATION RATIOS ARE MAINTAINED BY OTHER UTILITY OPERATING COMPANIES?

A71. Exhibit No. 15 displays capital structure data at year-end 2014 for the group of electric utility operating companies owned by the firms in the electric group relied on by Dr. Woolridge. As shown there, common equity ratios for these utilities ranged from 37.6% to 67.7% and averaged 49.6%. Over one-third of these electric operating companies had common equity ratios greater than 50%.

Q72. WHAT DOES THIS EVIDENCE SUGGEST WITH RESPECT TO DR. WOOLRIDGE'S ALLEGATIONS?

A72. This evidence refutes Dr. Woolridge's suggestion that the Companies' equity ratios should be adjusted downward. The capital structures proposed for the Companies fall within the range of capitalizations maintained by our Utility Group, as well for the electric operating companies corresponding to Dr. Woolridge's electric proxy group.

Utilities are facing significant capital investment plans, uncertainties over accommodating future environmental mandates, and ongoing regulatory risks. Coupled with the potential for turmoil in capital markets, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions. Given the comparability in overall risk measures between the Companies and the proxy group, there is no support for Dr. Woolridge's hypothetical capital structure.

X. RESPONSE TO MR. CHRISS

Q73. DID MR. CHRISS CONDUCT AN INDEPENDENT EVALUATION OF A FAIR ROE FOR THE COMPANIES?

A73. No. Mr. Chriss did not conduct any analyses of the cost of equity. His testimony was limited to a presentation of selected data concerning previously authorized ROEs. Based on this limited review, Mr. Chriss expressed his concern that a 10.5% ROE for the Companies is "excessive."[94]

[94] Chriss Direct at 7.

Q74. DO YOU AGREE WITH MR. CHRISS THAT ALLOWED ROES PROVIDE ONE BENCHMARK WORTHY OF CONSIDERATION IN THE COMMISSION'S EVALUATION?

A74. Yes, we do. Importantly, however, such comparisons of allowed ROEs are only one consideration. While this data can be useful in the KPSC's deliberations, it is not a substitute for the detailed analyses presented in our direct testimony.

Q75. DOES THE DATA PRESENTED BY MR. CHRISS CONFIRM YOUR CONCLUSION THAT DR. WOOLRIDGE'S AND MR. BAUDINO'S RECOMMENDATIONS ARE TOO LOW?

A75. Yes. Mr. Chriss cites an average allowed ROE of 10.1% for 2012-2015 and an average allowed return for vertically integrated utilities of 9.92% for 2014,[95] which confirms our earlier conclusion that the 8.75% and 8.60% ROE recommendations of Dr. Woolridge and Mr. Baudino fall well below average returns authorized for other utilities, and are insufficient to meet the requirements of regulatory standards.

Q76. DO YOU AGREE WITH THE INFERENCE THAT MR. CHRISS DRAWS FROM HIS REVIEW OR ALLOWED ROES?

A76. No. First, the data presented by Mr. Chriss does not include all rate case results compiled by Regulatory Research Associates "(RRA") and reported to investors by SNL financial. ROEs for electric utilities reported by RRA from 2012 through the 2014 are displayed in Table R-2, below:

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[95] Chriss Direct at 11.

TABLE R-2
ALLOWED ROEs FOR ELECTRIC UTILITIES

Year	ROE	No. Cases
2012	10.17%	58
2013	10.02%	50
2014	9.92%	37
	10.04%	145

As illustrated above, these returns result in an average ROE that is significantly higher than the 9.83% median reported by Mr. Chriss.

Second, there is no basis for Mr. Chriss to suggest that average authorized ROEs are somehow skewed upwards because of specific awards in certain states. Mr. Chriss points to ROEs above 10% awarded in Wisconsin, but he made no effort to examine results at the low-end of the range. For example the two 8.72% ROEs that set the minimum of the values reviewed by Mr. Chriss were both authorized in Illinois based on a fixed spread over Treasury bond yields, which presents a distorted picture of capital costs for utilities.[96] Similarly, the next-highest 9.0% value for Maui Electric Company incorporated a penalty related to that utility's integration of renewable generation and applies to a jurisdiction that has instituted full revenue decoupling. In short, while a review of historical authorized ROEs can provide a meaningful ROE benchmark, it is not a substitute for a thorough analysis of the cost of capital, such as that contained in our direct testimony and supporting the Companies' 10.5% requested ROE.

[96] For example, FERC recently discontinued its practice of adjusting ROEs based on changes in Treasury bond yields, noting that, "U.S. Treasury bond yields do not provide a reliable and consistent metric for tracking changes in ROE." Opinion No. 531, 147 FERC ¶ 61,234 at P 160 (2014).

Q77. FROM YOUR POSITION AS AN ECONOMIST, WHAT DO YOU MAKE OF MR. CHRISS'S ADMONITION (P. 11) TO CONSIDER CUSTOMER IMPACTS WHEN ESTABLISHING A FAIR ROE?

A77. First, 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 U.S. Supreme Court's regulatory standards embodied in the *Hope* and *Bluefield* decisions represent a balance between the interests of customers and investors, by setting forth the guidelines as to a fair ROE. Meanwhile, Mr. Chriss wrongly suggests that a lower ROE is *per se* in customers' benefit. This is not the case. 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. Chriss 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.

Q78. DOES THE 2013 NORTH CAROLINA SUPREME COURT DECISION CITED BY MR. CHRIS (P. 11) SUPPORT HIS ADMONITION?

A78. No.[97] The decision cited by Mr. Chris remanded a Duke Energy Carolinas ("Duke") case back to the North Carolina Utilities Commission ("NCUC") because in accepting the ROE in a stipulation the Commission's order did not address the substantive arguments raised by expert witnesses representing consumer interests. In 2014 there was a subsequent North Carolina Supreme Court Decision confirming the NCUC's Order on Remand (October, 23 2013).[98] In the Order on Remand the NCUC reached the same conclusion as to ROE but specifically addressed the substantive issues raised by witnesses on behalf of consumer interests. Our rebuttal testimony in this case is consistent with the guidance of the North Carolina Supreme Court because we have responded to every substantive argument in the testimony of opposing witnesses. The North Carolina Supreme Court decision also cited the finding of the Remand Order that reflects our argument that maintaining the utility's ability to attract capital is in customers' interest:

> 55. Continuous safe, adequate, and reliable electric service by [Duke] is essential to the well-being of the people, businesses, institutions, and economy of North Carolina.[99]

Just as being served by a utility that has reasonable access to capital is in the interest of consumers in North Carolina, so also is KU's access to capital essential to people, businesses, institutions, and the economy of Kentucky. The final conclusion of the December 19, 2014 decision by the North Carolina Supreme Court is consistent with KU's ROE request in this case:

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[97] Like Mr. Chriss, we are not attorneys and do not address the legal relevance of this North Carolina case to Kentucky rate cases.

[98] *See, In the Supreme Court of North Carolina, STATE EX REL. UTILS. COMM'N V. COOPER, ATT'Y GEN. No. 268A12-2 (Fined 19 December 2014)* at p. 4.

[99] Id., p. 10.

> These findings of fact not only demonstrate that the Commission considered the impact of changing economic conditions upon customers, but also specify how this factor influenced the Commission's decision to authorize a 10.5% ROE as agreed to in the Stipulation.[100]

Q79. DO YOU AGREE WITH MR. CHRISS'S ASSESSMENT REGARDING THE IMPACT OF CONSTRUCTION WORK IN PROGRESS ("CWIP")?

A79. No. While Mr. Chriss attempts to distinguish the risks of the Companies based on the opportunity to include CWIP in rate base, this is hardly novel or unique to the Companies and has been widely utilized since the 1970s to address the impact of construction costs on utilities' financial integrity.

Q80. WHAT IS CWIP?

A80. CWIP consists of investment in facilities built to meet service obligations that are not yet physically providing service. For an electric utility, CWIP can be sizeable as a result of the capital intensity of utility infrastructure investment and the extended construction periods involved with these facilities. During the construction phase, the utility must pay capital carrying costs (interest, dividends, etc.) on the investment in new facilities. These capital carrying costs are typically accrued for future recovery in the form of Allowance for Funds Used During Construction ("AFUDC"), which is included in rate base at the time the facilities are placed in service. Alternatively, regulators may allow CWIP to be included in rate base and thus permit the utility an opportunity to recover these capital costs through current rates.

Q81. WHAT IS THE FINANCIAL IMPACT OF CWIP?

A81. If CWIP is included in rate base, the utility's revenue requirements are increased by the capital costs associated with the new construction. As a result, since customers

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[100] Id., p. 12.

pay the capital carrying costs of CWIP in current rates, capitalized AFUDC is not added to plant cost. From the utility's standpoint, current cash flow is higher than it would have been otherwise. As a result, including CWIP in rate base improves a utility's cash flow and increases revenue requirements during the construction phase; however, this increase is offset in the future by the lower rate base that results from eliminating capitalized AFUDC.

While the level of a utility's earnings does not differ dramatically depending on whether or not CWIP is included in rate base, the cash flow implications can be significant, especially in the case of a large construction program. To finance the costs of construction, utilities such as the Companies must obtain financing in the form of common equity or long-term debt. If CWIP is not included in rate base, no cash is generated from current rates to meet the interest and dividend payments associated with these securities, which in turn must be financed.

The uncertainties that investors associate with cost deferrals and a deterioration in earnings quality are significant and many of the key indicators relied on by securities analysts and bond rating agencies focus on measures of cash flow. As a result, the greater risk associated with higher levels of non-cash earnings (*i.e.*, AFUDC) would ultimately be reflected in higher rates of return required by investors. 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.

Q82. IS THERE ANY MERIT TO MR. CHRISS'S CONTENTION (P. 8) THAT INCLUDING CWIP IN RATE BASE "SHIFTS RISKS TO RATEPAYERS?"

A82. No. Including CWIP in rate base will ease the financial pressure associated with the Companies' capital projects by improving cash flow and providing greater regulatory certainty. While instrumental in supporting financial integrity and ability to attract capital, including CWIP will not have a measurable impact on the overall investment risks of the Companies or investors' required rate of return. Including CWIP in rate base changes only the timing of cost recovery for projects included in CWIP. Accordingly, CWIP does not shift risks to ratepayers, as alleged by Mr. Chriss.

Q83. HAVE OTHER REGULATORS RECOGNIZED THE POTENTIAL BENEFITS ASSOCIATED WITH INCLUDING CWIP IN RATE BASE?

A83. Yes. Investors recognize that it is not uncommon for regulators to include CWIP in rate base when establishing rates. A study by the Edison Electric Institute observed that:

> 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 the inclusion of CWIP in rate base include CO, FL, GA, IN, KS, KY, LA, MI, MO, NC, NM, NV, SD, TN, VA, and WV.[101]

Accordingly, the cost of equity estimates developed for the proxy companies already reflects any impact associated with the opportunity to earn a return on CWIP. FERC has also recognized that including CWIP balances the interest of investors and customers, and the Commission has routinely allowed electric utilities to include CWIP in rate base.[102] FERC noted in *Order No. 679* that including CWIP in rate base provides "up-front regulatory certainty, rate stability and improved cash flow" that encourage investment by "easing the financial pressures" associated with construction programs.[103]

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[101] Edison Electric Institute, *Forward Test Years for US Electric Utilities* (August 2010).

[102] *Construction Work in Progress for Public Utilities; Inclusion of Costs in Rate Base*, Order No. 298, FERC Stats. & Regs. ¶ 30,455 (1983), order on reh'g, 25 FERC ¶ 61,023 (1983).

[103] *Order No.679* at P. 115. *See also, Order No. 679-A* at PP. 114-115.

Q84. IS MR. CHRISS'S POSITION WITH RESPECT TO CWIP CONSISTENT WITH ESTABLISHED PRECEDENT IN KENTUCKY?

A84. No. Mr. Chriss's recommendations conflict with the KPSC's long-established support for including CWIP without any downward adjustment to the Companies' ROE. Mr. Chriss has presented no evidence that would suggest the KPSC's longstanding practice no longer benefits customers or would otherwise undermine a constructive regulatory policy that is widespread in the industry. Moreover, while CWIP is supportive of the Companies' credit standing, it does not allow recovery of a return on construction expenditures outside of a rate proceeding. As a result, there can be a significant lag between the time that expenditures are incurred and when they are included in CWIP, which is exacerbated for utilities with large capital expenditure programs, such as the Companies'. Mr. Chriss fails to address these realities, which further disprove his assessment and recommendations.

Q85. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A85. Yes.

VERIFICATION

STATE OF Texas)
) **SS:**
COUNTY OF Hays)

The undersigned, **William E. Avera**, being duly sworn, deposes and says he is 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.

William E. Avera

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2 day of April 2015.

________________(SEAL)
Notary Public

My Commission Expires:

____

NOTARY PUBLIC STATE OF TEXAS
Robert Middelton Avera
Notary Public,
State of Texas
Expires:06-17-2018

VERIFICATION

STATE OF TEXAS)
) **SS:**
COUNTY OF TRAVIS)

The undersigned, **Adrien M. McKenzie**, being duly sworn, deposes and says he is Vice 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 08 day of April 2015.

NOTARY PUBLIC
STATE OF TEXAS
DAVID BLANCO
NOTARY PUBLIC
STATE OF TEXAS
MY COMM. EXP. 1/28/17

______________________________(SEAL)
Notary Public

My Commission Expires:

1/28/17

EXPECTED EARNINGS APPROACH **Exhibit No. 12**

WOOLRIDGE GROUP

		(a)	(b)	(c)
	Company	**Expected Return on Common Equity**	**Adjustment Factor**	**Adjusted Return on Common Equity**
1	ALLETE	9.50%	1.0240	9.73%
2	Alliant Energy	12.00%	1.0113	12.14%
3	Ameren Corp.	9.50%	1.0238	9.73%
4	American Elec Pwr	10.50%	1.0198	10.71%
5	Avista Corp.	8.50%	1.0286	8.74%
6	Black Hills Corp.	9.00%	1.0218	9.20%
7	CMS Energy Corp.	13.50%	1.0329	13.94%
8	Consolidated Edison	9.00%	1.0170	9.15%
9	Dominion Resources	17.00%	1.0403	17.69%
10	Duke Energy Corp.	8.00%	1.0134	8.11%
11	Edison International	11.00%	1.0312	11.34%
12	El Paso Electric	9.00%	1.0218	9.20%
13	Empire District Elec	8.50%	1.0205	8.67%
14	Entergy Corp.	9.00%	1.0165	9.15%
15	Eversource Energy	9.50%	1.0208	9.70%
16	FirstEnergy Corp.	8.00%	1.0229	8.18%
17	Great Plains Energy	7.50%	1.0149	7.61%
18	IDACORP, Inc.	8.50%	1.0206	8.67%
19	MGE Energy	13.50%	1.0312	13.92%
20	NorthWestern Corp.	9.50%	1.0518	9.99%
21	OGE Energy Corp.	11.00%	1.0237	11.26%
22	PG&E Corp.	9.50%	1.0312	9.80%
23	Pinnacle West Capital	9.50%	1.0247	9.73%
24	PNM Resources	9.50%	1.0160	9.65%
25	Portland General Elec.	9.00%	1.0358	9.32%
26	SCANA Corp.	10.50%	1.0304	10.82%
27	Southern Company	13.50%	1.0186	13.75%
28	Westar Energy	9.50%	1.0128	9.62%
29	Xcel Energy Inc.	10.00%	1.0248	10.25%
	Average (d)			**10.07%**
	Midpoint (e)			**10.78%**

(a) The Value Line Investment Survey (Jan. 30, Feb. 20, & Mar. 20, 2015).

(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).

(c) (a) x (b).

(d) Excludes highlighted figures.

(e) Average of low and high values.

EXPECTED EARNINGS APPROACH

BAUDINO PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	9.00%	1.0405	9.36%
2	Alliant Energy	12.00%	1.0202	12.24%
3	Avista Corp.	8.50%	1.0286	8.74%
4	CMS Energy Corp.	13.50%	1.0338	13.96%
5	Consolidated Edison	9.00%	1.0170	9.15%
6	Dominion Resources	17.00%	1.0403	17.69%
7	Duke Energy Corp.	8.00%	1.0134	8.11%
8	Edison International	11.00%	1.0312	11.34%
9	Empire District Elec	9.00%	1.0237	9.21%
10	Eversource Energy	9.50%	1.0208	9.70%
11	IDACORP, Inc.	8.50%	1.0206	8.67%
12	NorthWestern Corp.	9.50%	1.0518	9.99%
13	OGE Energy Corp.	12.00%	1.0323	12.39%
14	Pinnacle West Capital	9.50%	1.0247	9.73%
15	Portland General Elec.	9.00%	1.0358	9.32%
16	Southern Company	13.50%	1.0186	13.75%
17	Westar Energy	9.50%	1.0266	9.75%
18	Xcel Energy Inc.	10.00%	1.0248	10.25%
	Average (d)			**10.33%**
	Midpoint (e)			**11.03%**

(a) The Value Line Investment Survey (Dec. 19, 2014, Jan. 30 & Feb. 20, 2015).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) (a) x (b).
(d) Eliminates highlighted values.
(e) Average of low and high values.

<u>WOOLRIDGE GROUP</u>

	Company	(a) Allowed ROE
1	ALLETE	10.38%
2	Alliant Energy	9.50%
3	Ameren Corp.	9.19%
4	American Elec Pwr	10.28%
5	Avista Corp.	9.73%
6	Black Hills Corp.	9.83%
7	CMS Energy Corp.	10.30%
8	Dominion Resources	10.90%
9	Consolidated Edison	9.61%
10	Duke Energy Corp.	10.38%
11	Edison International	10.45%
12	El Paso Electric	NA
13	Empire District Elec	NA
14	Entergy Corp.	10.40%
15	Eversource Energy	9.15%
16	FirstEnergy Corp.	11.33%
17	Great Plains Energy	9.60%
18	IDACORP, Inc.	10.00%
19	MGE Energy	10.30%
20	NorthWestern Corp.	10.00%
21	OGE Energy Corp.	10.08%
22	PG&E Corp.	10.40%
23	Pinnacle West Capital	10.00%
24	PNM Resources	10.00%
25	Portland General Elec.	9.68%
26	SCANA Corp.	10.37%
27	Southern Company	12.50%
28	Westar Energy	10.00%
29	Xcel Energy Inc.	10.08%
	Average	**10.16%**
	Midpoint (b)	**10.83%**

(a) The Value Line Investment Survey (Dec. 19, 2014, Jan. 30 & Feb. 20, 2015).
(b) Average of low and high values.

BAUDINO PROXY GROUP

	Company	(a) Allowed ROE
1	ALLETE	10.38%
2	Alliant Energy	9.50%
3	Avista Corp.	9.73%
4	CMS Energy Corp.	10.30%
5	Consolidated Edison	9.61%
6	Dominion Resources	10.90%
7	Duke Energy Corp.	10.38%
8	Edison International	10.45%
9	Empire District Elec	NA
10	Eversource Energy	9.15%
11	IDACORP, Inc.	10.00%
12	NorthWestern Corp.	10.00%
13	OGE Energy Corp.	10.08%
14	Pinnacle West Capital	10.00%
15	Portland General Elec.	9.68%
16	Southern Company	12.50%
17	Westar Energy	10.00%
18	Xcel Energy Inc.	10.08%
	Average	**10.16%**
	Midpoint (b)	**10.83%**

(a) The Value Line Investment Survey (Dec. 19, 2014, Jan. 30 & Feb. 20, 2015).
(b) Average of low and high values.

BAUDINO CAPM ANALYSIS

EPS GROWTH

20-Year Treasury Bond, Value Line Beta

Market Required Return Estimate	
Expected Dividend Yield	0.76%
Expected Growth	12.00%
Required Return	12.76%
Risk-free Rate of Return, 20-Year Treasury Bond	
Average of Last Six Months	2.71%
Risk Premium	10.05%
Comparison Group Beta	0.73
Comparison Group Beta * Risk Premium	7.34%
CAPM Return on Equity	10.05%

Source: Exhibit No.___(RAB-6), page 2.

OPERATING CO. CAPITAL STRUCTURE

WOOLRIDGE PROXY GROUP

Operating Subsidiary	Short-term Debt	Long-term Debt	Preferred	Common Equity
AEP Ohio	0.0%	53.7%	0.0%	46.3%
AEP Texas	NA	NA	NA	NA
Alabama Power	0.0%	50.7%	5.2%	44.0%
Allegheny Generating Co.	4.2%	33.6%	0.0%	62.2%
Ameren Illinois Co.	0.6%	45.4%	1.3%	52.7%
Appalachian Power	0.0%	54.2%	0.0%	45.8%
Arizona Public Service Co.	1.8%	40.8%	0.0%	57.4%
Black Hills Power	0.0%	47.8%	0.0%	52.2%
Cheyenne Light Fuel & Power	NA	NA	NA	NA
Cleveland Electric Illuminating Co.	4.9%	52.3%	0.0%	42.8%
Connecticut Light & Power	2.2%	47.1%	1.9%	48.7%
Consolidated Edison of NY	2.0%	49.1%	0.0%	49.0%
Consumers Energy Company	0.6%	49.8%	0.3%	49.3%
Duke Energy Carolinas	0.0%	43.4%	0.0%	56.6%
Duke Energy Florida	0.8%	47.7%	0.0%	51.5%
Duke Energy Indiana	0.9%	49.2%	0.0%	49.9%
Duke Energy Ohio	7.1%	25.2%	0.0%	67.7%
Duke Energy Progress	0.0%	51.4%	0.0%	48.6%
Entergy Arkansas Inc.	1.1%	58.8%	0.0%	40.2%
Entergy Gulf States Louisiana LLC	0.0%	53.1%	0.3%	46.5%
Entergy Louisiana LLC	0.7%	53.1%	1.6%	44.6%
Entergy Mississippi Inc.	0.0%	51.1%	2.4%	46.5%
Entergy New Orleans Inc.	0.0%	49.8%	0.0%	50.2%
Entergy Texas Inc.	0.0%	62.4%	0.0%	37.6%
Georgia Power	0.8%	47.6%	1.3%	50.4%
Gulf Power	3.7%	46.7%	5.0%	44.6%
Idaho Power Co.	0.0%	59.6%	0.0%	40.4%
Indiana Michigan Power	3.5%	49.2%	0.0%	47.4%
Interstate Power & Light	0.0%	46.8%	5.3%	48.0%
Jersey Central Power and Light	5.0%	43.0%	0.0%	52.0%
Kansas City Power & Light Co.	9.3%	45.7%	0.0%	45.0%
Kansas Gas & Electric Co.	NA	NA	NA	NA
Kentucky Power	NA	NA	NA	NA
Madison Gas & Electric	0.7%	39.2%	0.0%	60.1%
Metropolitan Edison	2.0%	50.7%	0.0%	47.3%
Minnesota Power	NA	NA	NA	NA
Mississippi Power	0.0%	53.2%	0.7%	46.1%
Northern States Power Co. (MN)	1.6%	46.4%	0.0%	52.1%
Northern States Power Co. (WI)	5.8%	42.3%	0.0%	51.9%
NSTAR Electric Co.	6.6%	39.0%	0.9%	53.5%
Ohio Edison	0.0%	36.9%	0.0%	63.1%
Oklahoma Gas & Electric	0.0%	46.9%	0.0%	53.1%
Orange & Rockland	5.6%	46.4%	0.0%	48.0%
Pacific Gas & Electric Co.	2.0%	46.6%	0.8%	50.6%
Pennsylvania Electric Co.	0.0%	52.3%	0.0%	47.7%
Public Service Co. of Colorado	4.2%	42.5%	0.0%	53.4%
Public Service Co. of New Hampshire	3.8%	45.0%	0.0%	51.3%
Public Service Co. of New Mexico	0.0%	52.5%	0.4%	47.1%
Public Service Co. of Oklahoma	5.8%	55.4%	0.0%	38.8%
South Carolina Electric & Gas Co.	7.3%	44.1%	0.0%	48.7%
Southern California Edison	2.8%	41.6%	8.7%	47.0%
Southwestern Electric Power Co.	0.0%	50.5%	0.0%	49.5%
Southwestern Public Service Co.	1.2%	46.1%	0.0%	52.7%
Texas-New Mexico Power Co.	3.0%	39.8%	0.0%	57.2%
Toledo Edison Company	14.7%	42.0%	0.0%	43.3%
Union Electric Co.	1.2%	49.1%	1.0%	48.8%
Virginia Electric Power	6.7%	43.9%	0.0%	49.4%
Westar Energy	NA	NA	NA	NA
Western Massachusetts Electric Co.	1.7%	51.2%	0.0%	47.1%
Wisconsin Power & Light	0.0%	47.9%	0.0%	52.1%
Average	**2.3%**	**47.4%**	**0.7%**	**49.6%**

Source: Form 10-K Reports, FERC Form 1, GCS.

APPENDIX A

WORKPAPERS TO REBUTTAL TESTIMONY

OF

WILLIAM E. AVERA
AND
ADRIEN M. MCKENZIE

ALLETE NYSE-ALE

RECENT PRICE 52.12 | P/E RATIO 18.1 (Trailing: 18.0 / Median: 16.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 3.9% | VALUE LINE

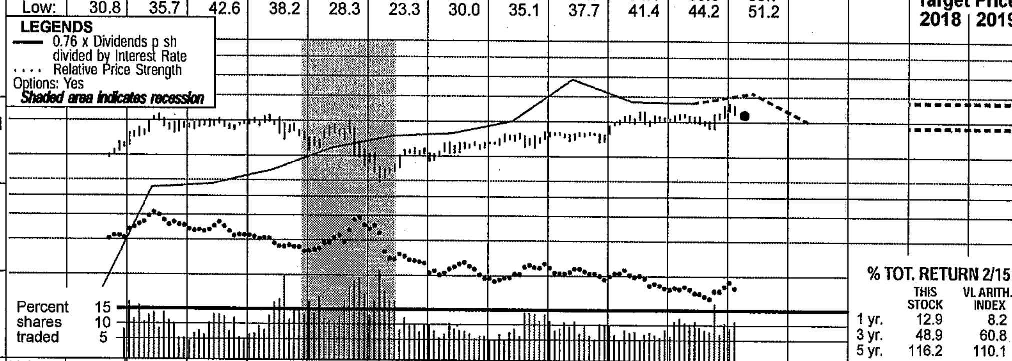
TIMELINESS 3 Lowered 9/19/14
SAFETY 2 New 10/1/04
TECHNICAL 3 Raised 3/20/15
BETA .80 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	37.5	51.7	49.3	51.3	49.0	35.3	37.9	42.5	42.7	54.1	58.0
Low:	30.8	35.7	42.6	38.2	28.3	23.3	30.0	35.1	37.7	41.4	44.2

High: 59.7 Low: 51.2 (2015)

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.76 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+15%)	8%
Low	45	(-15%)	1%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	0	1
to Sell	0	0	0	0	1	1	0	0	1

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	98	104	97
to Sell	75	75	90
Hld's(000)	29801	29758	32344

Percent shares traded 15 10 5

% TOT. RETURN 2/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.9	8.2
3 yr.	48.9	60.8
5 yr.	116.2	110.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
--	--	--	--	--	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	24.40	24.60	24.77	*28.20*	*30.15*	Revenues per sh	*35.00*
--	--	--	--	--	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	5.01	5.35	5.68	*6.15*	*6.60*	"Cash Flow" per sh	*8.00*
--	--	--	--	--	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	2.58	2.63	2.90	*3.05*	*3.25*	Earnings per sh A	*4.00*
--	--	--	--	--	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	1.84	1.90	1.96	*2.02*	*2.10*	Div'd Decl'd per sh B ■ †	*2.40*
--	--	--	--	--	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	10.30	7.93	12.48	*5.90*	*4.90*	Cap'l Spending per sh	*5.50*
--	--	--	--	--	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	*36.55*	*37.80*	Book Value per sh C	*42.25*
--	--	--	--	--	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	39.40	41.40	45.90	*47.50*	*47.75*	Common Shs Outst'g D	*48.50*
--	--	--	--	--	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	15.9	18.6	17.2	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
--	--	--	--	--	1.33	.95	.89	.79	.84	1.07	1.02	.92	1.01	1.05	.91	*Value Line*		Relative P/E Ratio	*.85*
--	--	--	--	--	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	4.5%	3.9%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
737.4	767.1	841.7	801.0	759.1	907.0	928.2	961.2	1018.4	1136.8	*1340*	*1440*	Revenues ($mill)	*1700*
68.0	77.3	87.6	82.5	61.0	75.3	93.8	97.1	104.7	124.8	*140*	*155*	Net Profit ($mill)	*190*
28.4%	37.5%	34.8%	34.3%	33.7%	37.2%	27.6%	28.1%	21.5%	22.6%	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
.4%	1.4%	6.6%	5.8%	12.8%	8.9%	2.7%	5.3%	4.4%	6.3%	*4.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
39.1%	35.1%	35.6%	41.6%	42.8%	44.2%	44.3%	43.7%	44.6%	44.2%	*44.0%*	*43.0%*	Long-Term Debt Ratio	*42.0%*
60.9%	64.9%	64.4%	58.4%	57.2%	55.8%	55.7%	56.3%	55.4%	55.8%	*56.0%*	*57.0%*	Common Equity Ratio	*58.0%*
990.6	1025.6	1153.5	1415.4	1625.3	1747.6	1937.2	2134.6	2425.9	2882.2	*3090*	*3155*	Total Capital ($mill)	*3525*
860.4	921.6	1104.5	1387.3	1622.7	1805.6	1982.7	2347.6	2576.5	3286.4	*3565*	*3640*	Net Plant ($mill)	*3975*
8.0%	8.6%	8.6%	6.7%	4.8%	5.4%	6.0%	5.6%	5.3%	5.2%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	*8.0%*	*8.5%*	Return on Shr. Equity	*9.5%*
11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	8.1%	7.8%	7.8%	*8.0%*	*8.5%*	Return on Com Equity E	*9.5%*
5.2%	5.0%	5.8%	3.9%	.5%	1.5%	2.9%	2.3%	2.2%	2.5%	*2.5%*	*3.0%*	Retained to Com Eq	*3.5%*
54%	57%	51%	61%	93%	81%	66%	71%	72%	67%	*67%*	*65%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 12/31/14
Total Debt $1377.2 mill. Due in 5 Yrs $285.6 mill.
LT Debt $1272.8 mill. LT Interest $57.3 mill.
(LT interest earned: 3.9x)
Leases, Uncapitalized Annual rentals $13.4 mill.

Pension Assets-12/14 $544.2 mill.
Oblig. $714.5 mill.
Pfd Stock None

Common Stock 45,953,851 shs.
as of 2/1/15

MARKET CAP: $2.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+1.1	-1.1	+.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.24	5.45	6.09
Capacity at Peak (Mw)	1790	1793	1985
Peak Load, Winter (Mw) F	1633	1646	1637
Annual Load Factor (%)	79.0	NA	NA
% Change Customers (avg.)	+.5	NA	NA
Fixed Charge Cov. (%)	341	306	345

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-.5%	--	6.0%
"Cash Flow"	6.0%	5.5%	7.0%
Earnings	7.0%	1.0%	7.0%
Dividends	NMF	2.0%	4.0%
Book Value	4.5%	5.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	240.0	216.4	248.8	256.0	961.2
2013	263.8	235.6	251.0	268.0	1018.4
2014	296.5	260.7	288.9	290.7	1136.8
2015	*320*	*325*	*345*	*350*	*1340*
2016	*360*	*345*	*365*	*370*	*1440*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2012	.66	.39	.78	.75	2.58
2013	.83	.35	.63	.82	2.63
2014	.80	.40	.97	.73	2.90
2015	*.85*	*.45*	*.85*	*.90*	*3.05*
2016	*.95*	*.45*	*.90*	*.95*	*3.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.445	.445	.445	.445	1.78
2012	.46	.46	.46	.46	1.84
2013	.475	.475	.475	.475	1.90
2014	.49	.49	.49	.49	1.96
2015	.505				

BUSINESS: ALLETE, Inc. is the parent of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric rev. breakdown: taconite mining/processing, 27%; paper/wood products, 9%; other industrial, 7%; residential, 12%; commercial, 13%; wholesale, 10% other, 22%. ALLETE Clean Energy owns renewable energy projects. Acq'd U.S. Water Services 2/15. Has real estate operation in FL. Generating sources: coal & lignite, 56%; wind, 7%; other, 3%; purchased, 34%. Fuel costs: 31% of revs. '14 deprec. rate: 2.9%. Has 1,600 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's earnings are likely to advance in 2015. Minnesota Power, the company's primary utility subsidiary, will benefit from a full year of income from a 205-megawatt wind project that was completed in December at a cost of $333 million. The utility gets current cost recovery for certain kinds of capital spending, such as a $250 million environmental upgrade to a coal-fired generating unit. In addition, Minnesota Power is experiencing load growth as some of its large industrial customers expand their operations. Most notably, Essar Steel expects to begin producing taconite pellets in the second half of 2015. Finally, the company's real estate assets in Florida (which ALLETE intends to sell) should break even this year. It lost $2 million in 2014. Our estimate is within management's guidance of $3.00-$3.20 a share.

There is some upside potential to profits this year. Minnesota Power plans to build a wind project for a utility in North Dakota, which would then (if the state regulators approve) buy the project. Prospective income from the sale is not included in ALLETE's guidance. If the regulators do not approve the deal, then Minnesota Power will sell the output under a long-term purchased-power contract.

ALLETE has made an acquisition. The company paid $168 million for an 87% interest in U.S. Water Services, which provides water management for industrial customers. Revenues were about $120 million last year, and the company expects top-line growth of 10%-15% annually. However, due to amortization that ALLETE will record under purchase accounting rules, the deal isn't likely to contribute to profits this year.

We forecast solid earnings growth in 2016. Current recovery of some capital spending and the ongoing effects of industrial expansion should help. We figure U.S. Water Services will also make a contribution.

The board of directors raised the dividend this quarter. The board increased the annual disbursement by $0.06 a share (3.1%).

The dividend yield and 3- to 5-year total return potential for ALLETE are about average, by utility standards.

Paul E. Debbas, CFA *March 20, 2015*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢; '05, ($1.84); gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next egs. report due early May. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred chgs. In '14: $7.78/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in '10: 10.38%; earned on avg. com. eq., '14: 8.6%. Reg. Clim.: Avg. (F) Summer peak in '12 & '13.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	80

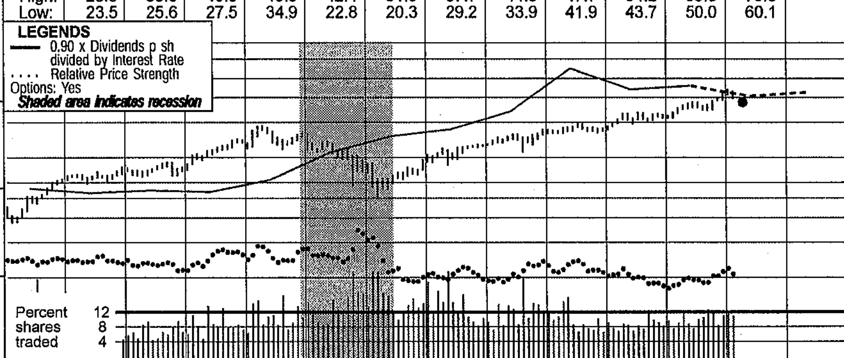
ALLIANT ENERGY NYSE-LNT

RECENT PRICE 60.67 | P/E RATIO 17.1 (Trailing: 17.5 Median: 14.0) | RELATIVE P/E RATIO 0.93 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Lowered 8/22/14
SAFETY 2 Raised 9/28/07
TECHNICAL 3 Raised 3/20/15
BETA .80 (1.00 = Market)

High:	28.8	30.6	40.0	46.5	42.4	31.5	37.7	44.5	47.7	54.2	69.8	70.8
Low:	23.5	25.6	27.5	34.9	22.8	20.3	29.2	33.9	41.9	43.7	50.0	60.1

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2018 | 2019 | 2020
120 100 80 64 48 32 24 20 16 12 8

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+25%)	9%
Low	55	(-10%)	2%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	1	0	0	1	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	160	152	154
to Sell	134	151	158
Hld's(000)	67528	67088	68200

Percent shares traded 12 8 4

% TOT. RETURN 2/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.3	8.2
3 yr.	64.9	60.8
5 yr.	142.5	110.1

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
28.02	28.93	31.15	33.33	31.02	30.81	33.02	27.88	29.54	30.20	***31.55***	***32.15***	Revenues per sh	***34.80***
5.46	4.33	5.12	4.56	4.21	5.21	5.51	5.90	6.68	6.88	***7.05***	***7.45***	"Cash Flow" per sh	***8.00***
2.21	2.06	2.69	2.54	1.89	2.75	2.75	3.05	3.29	3.48	***3.60***	***3.85***	Earnings per sh A	***4.25***
1.05	1.15	1.27	1.40	1.50	1.58	1.70	1.80	1.88	2.04	***2.20***	***2.36***	Div'd Decl'd per sh B ■ †	***2.85***
4.51	3.42	4.91	7.96	10.87	7.82	6.07	10.43	6.63	7.56	***8.85***	***9.00***	Cap'l Spending per sh	***9.80***
20.85	22.83	24.30	25.56	25.07	26.09	27.14	28.25	29.58	31.09	***31.75***	***32.45***	Book Value per sh C	***34.65***
117.04	116.13	110.36	110.45	110.66	110.89	111.02	110.99	110.94	110.94	***111.00***	***112.00***	Common Shs Outst'g D	***115.00***
12.6	16.8	15.1	13.4	13.9	12.5	14.5	14.5	15.3	16.6	***Bold figures are***		Avg Ann'l P/E Ratio	***15.0***
.67	.91	.80	.81	.93	.80	.91	.92	.86	.88	***Value Line***		Relative P/E Ratio	***.95***
3.8%	3.3%	3.1%	4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	***estimates***		Avg Ann'l Div'd Yield	***4.0%***
3279.6	3359.4	3437.6	3681.7	3432.8	3416.1	3665.3	3094.5	3276.8	3350.3	***3500***	***3600***	Revenues ($mill)	***4000***
337.8	260.1	320.8	280.0	208.6	303.9	304.4	337.8	382.1	385.5	***400***	***430***	Net Profit ($mill)	***490***
19.0%	43.8%	44.4%	33.4%	--	30.1%	19.0%	21.5%	12.4%	10.1%	***15.0%***	***20.0%***	Income Tax Rate	***20.0%***
3.0%	3.1%	2.4%	--	--	--	--	--	8.8%	6.5%	***7.0%***	***7.0%***	AFUDC % to Net Profit	***7.0%***
41.6%	31.4%	32.4%	36.3%	44.3%	46.3%	45.7%	48.4%	46.1%	49.7%	***47.5%***	***47.5%***	Long-Term Debt Ratio	***47.5%***
53.1%	62.9%	61.9%	58.6%	51.2%	49.5%	50.9%	48.4%	50.8%	47.5%	***49.5%***	***49.5%***	Common Equity Ratio	***49.5%***
4599.1	4218.4	4329.5	4815.6	5423.0	5840.8	5921.2	6476.6	6461.0	7257.2	***7500***	***7500***	Total Capital ($mill)	***7800***
4866.2	4944.9	4679.9	5353.5	6203.0	6730.6	7037.1	7838.0	7147.3	6442.0	***8000***	***8000***	Net Plant ($mill)	***9000***
8.9%	7.5%	8.6%	7.0%	5.1%	6.6%	6.4%	6.3%	7.0%	6.3%	***6.5%***	***6.5%***	Return on Total Cap'l	***7.0%***
12.6%	9.0%	11.0%	9.1%	6.9%	9.7%	9.5%	10.1%	11.0%	10.6%	***11.0%***	***11.0%***	Return on Shr. Equity	***11.5%***
13.1%	9.1%	11.3%	9.3%	6.8%	9.9%	9.5%	10.3%	11.3%	10.9%	***11.5%***	***11.5%***	Return on Com Equity E	***12.0%***
8.1%	4.0%	5.9%	3.8%	.9%	3.8%	3.3%	3.9%	4.9%	4.3%	***4.5%***	***4.5%***	Retained to Com Eq	***5.0%***
42%	59%	50%	62%	88%	64%	67%	64%	57%	61%	***61%***	***61%***	All Div'ds to Net Prof	***67%***

CAPITAL STRUCTURE as of 12/31/14
Total Debt $3789.7 mill. **Due in 5 Yrs** $1100.0 mill.
LT Debt $3606.7 mill. **LT Interest** $60.0 mill.
(LT interest earned: 10.0x)

Pension Assets-12/14 $1022.9 mill. **Oblig.** $1301.5 mill.
Pfd Stock $200.0 mill. **Pfd Div'd** $10.2 mill.
8,000,000 shs.

Common Stock 110,935,680 shs.

MARKET CAP: $6.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+.3	+.1	+.1
Avg. Indust. Use (MWH)	11555	11471	11821
Avg. Indust. Revs. per KWH (¢)	6.42	6.75	6.85
Capacity at Peak (Mw)	5886	5820	5426
Peak Load, Summer (Mw)	5886	5820	5426
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.4	+.4
Fixed Charge Cov. (%)	332	295	320

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	0.5%	-1.5%	*4.0%*
"Cash Flow"	4.0%	7.0%	*6.0%*
Earnings	8.0%	6.5%	*6.0%*
Dividends	3.5%	6.5%	*4.5%*
Book Value	3.5%	3.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	765.7	690.3	887.6	750.9	3094.5
2013	859.6	718.0	866.6	832.6	3276.8
2014	952.8	750.3	843.1	804.1	3350.3
2015	***950***	***800***	***950***	***800***	***3500***
2016	***975***	***850***	***975***	***800***	***3600***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.50	.58	1.34	.63	3.05
2013	.72	.59	1.43	.55	3.29
2014	.97	.56	1.40	.55	3.48
2015	***.85***	***.60***	***1.55***	***.60***	***3.60***
2016	***.90***	***.65***	***1.65***	***.65***	***3.85***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.425	.425	.425	.425	1.70
2012	.45	.45	.45	.45	1.80
2013	.47	.47	.47	.47	1.88
2014	.51	.51	.51	.51	2.04
2015	.55				

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 44%; IA, 55%; MN, 1%. Elect. rev.: residential, 39%; commercial, 24%; industrial, 30%; wholesale, 6%; other, 1%. Fuel sources, 2014: coal, 47%; nuclear, 17%; gas, 4%; other, 32%. Fuel costs: 50% of revs. 2014 depreciation rate: 5.5%. Estimated plant age: 12 years. Has 4,200 employees. Chairman & Chief Executive Officer: Patricia L. Kampling. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy is investing heavily in infrastructure. The Madison, Wisconsin-based utility deployed roughly $1 billion in capital expenditures last year. According to management, it was one of the most active construction years in company history, with over $335 million poured into energy delivery systems alone. The goal of that considerable investment was to keep pace with customer growth, and bring natural gas services to communities which did not have access before.

Carbon emission reductions remain a top priority. During 2014, Alliant made significant progress transitioning its coal-fired facilities to produce higher levels of natural gas fueled generation (which is safer for the environment). The company also increased its use of renewable energy in many of its plants. Additionally, Alliant is constructing several new installations known as wetland systems that will improve the treatment of wastewater around its facilities.

We estimate earnings growth will be in the low-to mid-single-digit range over the next two years. Our 2015 forecast is at the midpoint of management's share-net guidance of $3.45–$3.75, reflecting a slight increase in revenue and further CapEx plans. Moreover, Alliant should benefit from the certainty of several rate settlements that it achieved during the past year for its retail division. For 2016, we think the company will try for further rate increases. We're basing our forecast on reasonable regulatory treatment from state officials.

The board of directors has raised the dividend. The quarterly distribution was increased $0.04 a share (8%), and the annualized payout is now $2.20. For the utility sector, the equity's current yield of around 3.6% is about average for the industry. The company is targeting a payout ratio of 60%-70%.

These shares may appeal to some income-oriented investors. The dividend is well supported by Alliant's predictable cash flows, and the yield is decent, though unspectacular. However, at its most recent quotation, the issue offers below average long-term capital appreciation potential. As such, subscribers seeking upside may want to look elsewhere.

Daniel Henigson *March 20, 2015*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '03, net 24¢; '04, (58¢); '05, ($1.05); '06, 83¢; '07, $1.09; '08, 7¢; '09, (88¢); '10, (15¢); '11, (1¢); '12, (16¢). Next egs. rpt. due early May.
(B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail.
(C) Incl. deferred chgs. In '14: $90.0 mill., $0.77/sh. (D) In mill. (E) Rate base: Orig. cost. Rates all'd on com. eq. in IA in '14: 10.9%; in WI in '14 Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	75

AMEREN NYSE-AEE

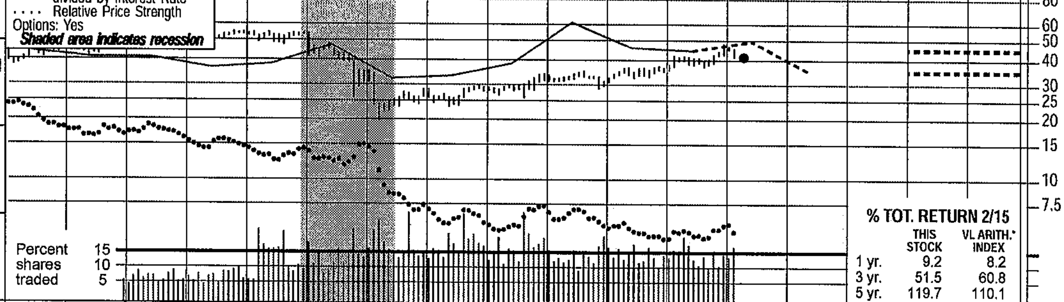
RECENT PRICE 41.47 | P/E RATIO 16.7 (Trailing: 17.2 Median: 15.0) | RELATIVE P/E RATIO 0.91 | DIV'D YLD 4.0% | VALUE LINE

TIMELINESS 3 Raised 3/6/15
SAFETY 2 Raised 6/20/14
TECHNICAL 2 Raised 3/20/15
BETA .75 (1.00 = Market)

High:	50.4	56.8	55.2	55.0	54.3	35.3	29.9	34.1	35.3	37.3	48.1	46.8		
Low:	40.6	47.5	48.0	47.1	25.5	19.5	23.1	25.5	28.4	30.6	35.2	40.5		

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.69 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+10%)	6%
Low	35	(-15%)	1%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	2	0	0	0	0	0	0	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	178	167	180
to Sell	189	197	199
Hld's(000)	159084	160810	157366

% TOT. RETURN 2/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.2	8.2
3 yr.	51.5	60.8
5 yr.	119.7	110.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
25.68	28.10	32.64	24.93	28.20	26.43	33.12	33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	26.15	27.20	Revenues per sh	30.00
5.36	6.11	6.33	5.28	6.29	5.57	6.10	6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.75	6.10	6.50	"Cash Flow" per sh	7.75
2.81	3.33	3.41	2.66	3.14	2.82	3.13	2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.55	2.75	Earnings per sh A	3.25
2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.65	1.69	Div'd Decl'd per sh B ■	1.85
4.16	6.77	7.99	5.11	4.19	4.13	4.63	4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.65	8.10	7.15	Cap'l Spending per sh	7.00
22.52	23.30	24.26	24.93	26.73	29.71	31.09	31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.65	28.60	29.65	Book Value per sh C	34.00
137.22	137.22	138.05	154.10	162.90	195.20	204.70	206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.65	242.65	242.65	Common Shs Outst'g D	250.00
13.5	11.0	12.1	15.8	13.5	16.3	16.7	19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	Bold figures are		Avg Ann'l P/E Ratio	12.5
.77	.72	.62	.86	.77	.86	.89	1.05	.92	.85	.62	.62	.75	.85	.93	.88	Value Line		Relative P/E Ratio	.80
6.7%	6.9%	6.2%	6.1%	6.0%	5.5%	4.9%	4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	estimates		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $6697 mill. Due in 5 Yrs $2276 mill.
LT Debt $5825 mill. LT Interest $317 mill.
(LT interest earned: 3.6x)
Leases, Uncapitalized Annual rentals $14 mill.
Pension Assets-12/13 $3461 mill.
Oblig. $3900 mill.
Pfd Stock $142 mill. Pfd Div'd $8 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 616,323 sh. 4.00% to 6.625%, $100 par, redeem. $100-$104/sh.
Common Stock 242,634,798 shs. as of 10/31/14
MARKET CAP: $10.1 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
6780.0	6880.0	7546.0	7839.0	7090.0	7638.0	7531.0	6828.0	5838.0	6053.0	6350	6600	Revenues ($mill)	7500
628.0	547.0	629.0	615.0	624.0	669.0	602.0	589.0	518.0	593.0	630	675	Net Profit ($mill)	830
35.6%	32.7%	33.5%	33.7%	34.7%	36.8%	37.3%	36.9%	37.5%	38.9%	38.0%	38.5%	Income Tax Rate	38.5%
2.9%	.7%	.8%	4.6%	5.8%	7.8%	5.6%	6.1%	7.1%	6.0%	7.0%	6.0%	AFUDC % to Net Profit	4.0%
44.9%	43.8%	45.0%	47.8%	49.7%	48.2%	45.3%	49.5%	45.2%	47.0%	47.0%	45.5%	Long-Term Debt Ratio	45.0%
53.3%	54.6%	53.4%	50.8%	49.1%	50.9%	53.7%	49.4%	53.7%	51.5%	52.0%	53.0%	Common Equity Ratio	54.0%
11932	12063	12654	13712	15991	15185	14738	13384	12190	12975	13300	13525	Total Capital ($mill)	15700
13572	14286	15069	16567	17610	17853	18127	16096	16205	17424	18525	19350	Net Plant ($mill)	21500
6.5%	5.7%	6.2%	5.7%	5.3%	6.0%	5.6%	6.0%	5.6%	5.5%	6.0%	6.0%	Return on Total Cap'l	6.5%
9.5%	8.1%	9.0%	8.6%	7.8%	8.5%	7.5%	8.7%	7.7%	8.5%	9.0%	9.0%	Return on Shr. Equity	9.5%
9.7%	8.1%	9.2%	8.7%	7.8%	8.6%	7.5%	8.8%	7.8%	8.5%	9.0%	9.5%	Return on Com Equity E	9.5%
1.7%	.2%	1.3%	1.0%	3.5%	3.8%	2.8%	3.0%	1.9%	3.0%	3.0%	3.5%	Retained to Com Eq	4.5%
83%	97%	86%	88%	56%	56%	63%	66%	76%	67%	64%	61%	All Div'ds to Net Prof	56%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-1.9	-.7	-.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.93	4.80	4.96
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	295	291	289

BUSINESS: Ameren Corp. is a holding company formed through the merger of Union Electric and CIPSCO. Acquired CILCORP 1/03; Illinois Power 10/04. Has 1.2 mill. electric and 127,000 gas customers in Missouri; 1.2 mill. electric and 811,000 gas customers in Illinois. Discont. power-generation op. in '13. Electric rev. breakdown: residential, 46%; commercial, 33%; industrial, 12%; other, 9%. Generating sources: coal, 70%; nuclear, 11%; hydro, 2%; gas, 1%; purchased, 16%. Fuel costs: 32% of revs. '13 reported depr. rates: 3%-4%. Has 8,500 employees. Chairman: Thomas R. Voss. President & CEO: Warner L. Baxter. Inc.: MO. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	-.5%	-5.0%	1.0%
"Cash Flow"	-.5%	-2.5%	4.5%
Earnings	-2.5%	-4.0%	5.0%
Dividends	-4.5%	-9.0%	2.0%
Book Value	1.5%	-2.0%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1658	1660	2001	1509	6828.0
2013	1475	1403	1638	1322	5838.0
2014	1594	1419	1670	1370	6053.0
2015	1650	1475	1800	1425	6350
2016	1725	1550	1850	1475	6600

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	d.11	.87	1.54	.11	2.41
2013	.22	.44	1.25	.19	2.10
2014	.40	.62	1.20	.19	2.40
2015	.25	.70	1.35	.25	2.55
2016	.30	.70	1.45	.30	2.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.385	.385	.385	.40	1.56
2012	.40	.40	.40	.40	1.60
2013	.40	.40	.40	.40	1.60
2014	.40	.40	.40	.41	1.61
2015	.41				

Ameren has rate cases pending in Missouri and Illinois. In Missouri, the utility is seeking an electric rate increase of $190 million, based on a return of 10.4% on a common-equity ratio of 51.8%. Ameren is asking for a continuation of various regulatory mechanisms, such as a fuel adjustment clause and a tracker for storm costs. The staff of the Missouri commission is recommending an allowed ROE of just 9.25%, and intervenor groups are proposing similar figures. A decision is expected in May, with new tariffs taking effect in June. In Illinois, Ameren is asking for a gas rate hike of $53 million, based on a 10.0%-10.5% return on a 50% common-equity ratio. The utility is also requesting a regulatory mechanism to decouple revenues from volume for small customers. An order is expected by December, with new tariffs taking effect in January.

Earnings will probably advance this year. Ameren will benefit from the absence of a refueling outage at the Callaway nuclear plant, a full year's benefit from the refinancing of high-cost debt last May, and (assuming reasonable regulatory treatment) a partial year of rate relief in Missouri. Spending on electric transmission is another plus, as Ameren earns a return on its current investment through a federally regulated formula rate plan. Our estimate is at the midpoint of management's guidance of $2.45-$2.65 a share.

We forecast high single-digit profit growth in 2016. Additional rate relief should be the primary factor.

Electric transmission is a key growth area for Ameren. The company's capital budget calls for spending of $2.3 billion through 2019. Although it appears almost certain that its allowed ROE on transmission will be cut from 12.38% currently (in fact, Ameren took an undisclosed reserve in the fourth quarter of 2014), the utility will be able to make up for part of the reduction through a half-percentage-point incentive "adder." Moreover, the allowed ROE will probably still be above its allowed ROEs in Missouri and Illinois.

The dividend yield of Ameren stock is about average for a utility. The company has good earnings growth prospects through 2018-2020, but in our view, these are reflected in the quotation.

Paul E. Debbas, CFA *March 20, 2015*

(A) Diluted EPS. Excl. nonrecur. gain (losses): '03, 11¢; '05, (11¢); '10, ($2.19); '11, (32¢); '12, ($6.42); loss from disc. ops.: '13, 92¢. '14 EPS don't add due to rounding. Next egs. report due early May. (B) Div'ds histor. paid in late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '13: $6.90/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in MO in '13: 9.8% elec., in '11: none specified gas; in IL in '14: 8.7% elec., 9.06% gas; earned on avg. com. eq., '13: 7.6%. Regulatory Climate: MO, Avg.; IL, Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	10
Earnings Predictability	85

AMERICAN ELEC. PWR. NYSE-AEP

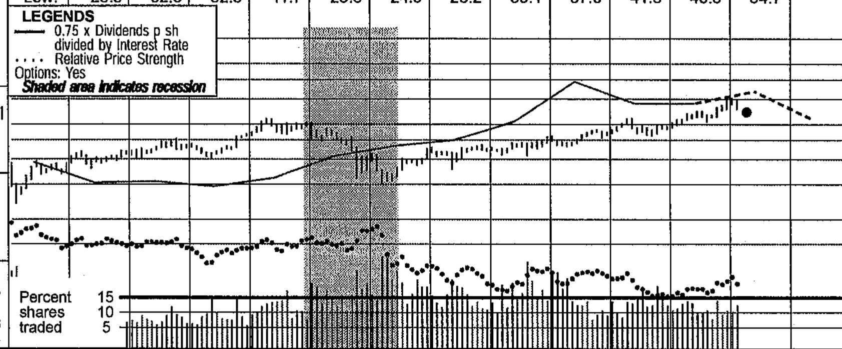
RECENT PRICE 55.26 | P/E RATIO 16.5 (Trailing: 16.1 Median: 13.0) | RELATIVE P/E RATIO 0.90 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Raised 3/6/15
SAFETY 2 Raised 9/19/14
TECHNICAL 3 Raised 3/20/15
BETA .70 (1.00 = Market)

High:	35.5	40.8	43.1	51.2	49.1	36.5	37.9	41.7	45.4	51.6	63.2	65.4		
Low:	28.5	32.3	32.3	41.7	25.5	24.0	28.2	33.1	37.0	41.8	45.8	54.7		

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.75 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+25%)	10%
Low	45	(-20%)	Nil

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	12	0	0	0	0	0	0	0
to Sell	0	6	0	0	2	0	0	0	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	338	325	361
to Sell	267	301	308
Hld's(000)	323714	326207	326985

Percent shares traded 15 / 10 / 5

% TOT. RETURN 2/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.1	8.2
3 yr.	73.3	60.8
5 yr.	114.1	110.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
35.63	42.53	190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.75	34.55	35.85	Revenues per sh	41.00
6.36	5.11	7.65	6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	6.64	6.75	7.25	7.50	7.85	"Cash Flow" per sh	9.25
2.69	1.04	3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.50	3.65	Earnings per sh A	4.50
2.40	2.40	2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	Div'd Decl'd per sh B ■	2.65
4.47	5.51	5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.65	9.30	8.05	Cap'l Spending per sh	8.50
25.79	25.01	25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.35	35.75	37.25	Book Value per sh C	42.25
194.10	322.02	322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	490.00	492.00	494.00	Common Shs Outst'g D	500.00
14.3	34.3	13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	Bold figures are		Avg Ann'l P/E Ratio	13.0
.82	2.23	.71	.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	.88	.81	.84	Value Line		Relative P/E Ratio	.80
6.2%	6.7%	5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	estimates		Avg Ann'l Div'd Yield	4.5%

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
12111	12622	13380	14440	13489	14427	15116	14945	15357	17020	17000	17700	Revenues ($mill)	20450
1036.0	1131.0	1147.0	1208.0	1365.0	1248.0	1513.0	1443.0	1549.0	1634.0	1675	1755	Net Profit ($mill)	2185
29.3%	33.0%	31.1%	31.3%	29.7%	34.8%	31.7%	33.9%	36.2%	37.8%	36.0%	36.0%	Income Tax Rate	36.0%
5.4%	9.9%	9.8%	9.9%	10.9%	10.4%	10.6%	11.2%	7.3%	9.0%	10.0%	7.0%	AFUDC % to Net Profit	7.0%
54.8%	56.7%	58.3%	59.1%	54.4%	53.1%	50.7%	50.6%	51.1%	49.0%	50.0%	49.0%	Long-Term Debt Ratio	48.5%
44.9%	43.0%	41.4%	40.7%	45.4%	46.7%	49.3%	49.4%	48.9%	51.0%	50.0%	51.0%	Common Equity Ratio	51.5%
20222	21902	24342	26290	28958	29184	29747	30823	32913	34050	35300	36050	Total Capital ($mill)	41100
24284	26781	29870	32987	34344	35674	36971	38763	40997	44117	46750	48650	Net Plant ($mill)	54300
6.6%	6.7%	6.3%	6.2%	6.2%	5.7%	6.6%	6.1%	6.0%	6.0%	6.0%	6.0%	Return on Total Cap'l	6.5%
11.3%	11.9%	11.3%	11.2%	10.3%	9.1%	10.3%	9.5%	9.6%	9.5%	9.5%	9.5%	Return on Shr. Equity	10.5%
11.3%	12.0%	11.4%	11.3%	10.4%	9.1%	10.3%	9.5%	9.6%	9.5%	10.0%	10.0%	Return on Com Equity E	10.5%
5.2%	5.7%	5.1%	5.1%	4.6%	3.1%	4.2%	3.5%	3.7%	4.0%	4.0%	4.0%	Retained to Com Eq	4.5%
54%	53%	55%	55%	56%	66%	60%	63%	62%	64%	63%	64%	All Div'ds to Net Prof	61%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $19340 mill. **Due in 5 Yrs** $9356 mill.
LT Debt $15677 mill. **LT Interest** $713 mill.
Incl. $2230 mill. securitized bonds.
(LT interest earned: 3.7x)

Leases, Uncapitalized Annual rentals $288 mill.
Pension Assets-12/13 $4711 mill. **Oblig.** $4841 mill.
Pfd Stock None

Common Stock 489,240,481 shs.
as of 10/23/14
MARKET CAP: $27 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+1.2	-2.1	-1.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.95	4.69	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	286	280	326

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	-10.0%	-1.5%	4.0%
"Cash Flow"	--	--	4.5%
Earnings	.5%	1.5%	5.5%
Dividends	-1.5%	4.0%	5.0%
Book Value	3.5%	4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3625	3551	4156	3613	14945
2013	3826	3582	4176	3773	15357
2014	4648	4044	4302	4026	17020
2015	4350	4100	4500	4050	17000
2016	4550	4250	4700	4200	17700

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.80	.75	1.00	.43	2.98
2013	.75	.73	1.10	.60	3.18
2014	1.15	.80	1.01	.39	3.34
2015	1.00	.80	1.15	.55	3.50
2016	1.05	.85	1.20	.55	3.65

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.46	.46	.46	.47	1.85
2012	.47	.47	.47	.47	1.88
2013	.47	.49	.49	.50	1.95
2014	.50	.50	.50	.53	2.03
2015	.53				

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves 5.3 mill. customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. Electric revenue breakdown: residential, 40%; commercial, 23%; industrial, 19%; wholesale, 15%; other, 3%. Sold 50% stake in Yorkshire Holdings (British utility) '01; sold SEEBOARD (British utility) '02; sold Houston Pipeline '05. Generating sources not available. Fuel costs: 36% of revenues. '13 reported deprec. rates (utility): 1.1%-7.9%. Has 18,500 employees. Chairman, President & CEO: Nicholas K. Akins. Inc.: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Tel.: 614-716-1000. Internet: www.aep.com.

What will American Electric Power do with its nonregulated generating assets in Ohio? The company had proposed a purchased-power agreement with four plants, which was intended to provide these assets with a stable source of income. The state commission rejected AEP's proposal, but did not prohibit purchased-power contracts. Now, the company must decide whether to put forth a revised proposal, or sell the assets. In fact, AEP has hired an investment-banking firm to evaluate a sale. Another company with nonregulated generating units in Ohio, Duke Energy, reached an agreement to sell these plants last year. Duke fared better than it had originally expected, although the units were still sold at a loss. In any case, AEP has been striving to make itself a more regulated company in recent years. We don't know when management will announce its plans.

We estimate mid-single-digit earnings growth this year and next. We are basing our estimates on retention of AEP's nonregulated generating assets. Due to conditions in the power markets, the income from these assets will probably decline in 2015 and 2016. Even so, rising profits from the regulated operations should outweigh this falloff. Some of AEP's utilities are asking for rate increases, and the company's electric transmission operations are increasing their contribution as more capital is invested in this area. Over the next three years, AEP has budgeted more than $4.8 billion for transmission capital expenditures. Our earnings estimates for 2015 and 2016 are at the midpoint of management's targeted ranges of $3.40-$3.60 a share and $3.45-$3.85 a share, respectively.

Rate cases are pending in West Virginia and Kentucky. In West Virginia, Appalachian Power is seeking a rate hike of $226 million, based on a 10.62% return on equity. An order is due on May 26th. Kentucky Power filed for a rate increase of $70 million, based on the same 10.62% ROE. New tariffs should take effect in mid-2015.

This stock has a dividend yield and 3- to 5-year total return potential that are about average, by utility standards.

Paul E. Debbas, CFA *March 20, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); discont. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢. '11 EPS don't add due to rounding. Next egs. report due late Apr. (B) Div'ds historically paid early Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '13: $18.20/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.65%-10.9%; earned on avg. com. eq., '13: 9.9%. Regul. Clim.: Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	90

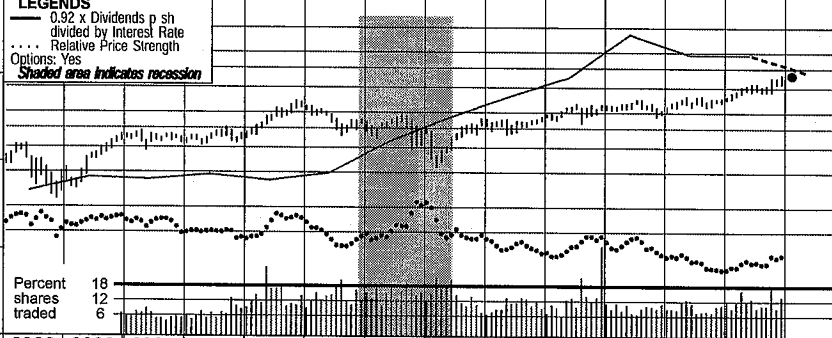
AVISTA CORP. NYSE-AVA

RECENT PRICE **36.87** | P/E RATIO **18.2** (Trailing: 19.3 Median: 16.0) | RELATIVE P/E RATIO **0.99** | DIV'D YLD **3.6%** | VALUE LINE

TIMELINESS **3** Lowered 11/14/14
SAFETY **2** Raised 5/7/10
TECHNICAL **2** Raised 1/16/15
BETA .80 (1.00 = Market)

High:	18.7	19.4	20.2	27.5	25.8	23.6	22.4	22.8	26.5	28.0	29.3	37.4
Low:	9.8	15.4	16.3	17.6	18.2	15.5	12.7	18.5	21.1	22.8	24.1	27.7

LEGENDS
— 0.92 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2017 | 2018 | 2019

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(-5%)	3%
Low	25	(-30%)	-4%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	6	0	1	1	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	118	97	99
to Sell	76	92	107
Hld's(000)	41191	40836	41104

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	30.5	6.9
3 yr.	56.5	73.7
5 yr.	105.2	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
91.07	221.75	167.59	126.17	20.41	23.24	23.76	27.98	28.68	26.80	30.77	27.58	27.29	27.73	25.86	26.94	*23.70*	*25.00*	Revenues per sh	*28.25*
3.47	2.28	3.31	2.71	2.19	2.63	2.35	2.72	4.27	2.93	3.98	4.45	3.62	3.78	3.70	4.36	*4.50*	*4.65*	"Cash Flow" per sh	*5.25*
1.28	.12	1.76	1.20	.67	1.02	.73	.92	1.47	.72	1.36	1.58	1.65	1.72	1.32	1.85	*1.95*	*2.00*	Earnings per sh A	*2.25*
1.05	.48	.48	.48	.48	.49	.52	.55	.57	.60	.69	.81	1.00	1.10	1.16	1.22	1.27	*1.32*	Div'd Decl'd per sh B ■	*1.50*
2.70	3.30	4.24	5.92	1.74	2.21	2.47	3.23	3.14	4.04	4.09	3.86	3.64	4.20	4.61	5.05	*5.90*	*5.85*	Cap'l Spending per sh	*6.00*
11.76	10.69	15.34	15.12	14.84	15.54	15.54	15.87	17.46	17.27	18.30	19.17	19.71	20.30	21.06	21.61	*23.90*	*24.80*	Book Value per sh C	*26.75*
40.45	35.65	47.21	47.63	48.04	48.34	48.47	48.59	52.51	52.91	54.49	54.84	57.12	58.42	59.81	60.08	*62.25*	*63.00*	Common Shs Outst'g D	*64.50*
16.5	NMF	13.6	13.7	19.3	13.8	24.4	19.4	15.4	30.9	15.0	11.4	12.7	14.1	19.3	14.6	*16.3*		Avg Ann'l P/E Ratio	*14.0*
.86	NMF	.88	.70	1.05	.79	1.29	1.03	.83	1.64	.90	.76	.81	.88	1.23	.82	*.85*		Relative P/E Ratio	*.90*
5.0%	2.8%	2.0%	2.9%	3.7%	3.5%	2.9%	3.0%	2.5%	2.7%	3.4%	4.5%	4.8%	4.5%	4.6%	4.5%	4.0%		Avg Ann'l Div'd Yield	*4.8%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1510.9 mill. Due in 5 Yrs $528.2 mill.
LT Debt $1463.8 mill. LT Interest $73.2 mill.
Incl. $51.5 mill. debt to affiliated trusts.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $6.7 mill.
Pension Assets-12/13 $481.5 mill.
Oblig. $527.0 mill.
Pfd Stock None

Common Stock 62,239,441 shs.
as of 10/31/14
MARKET CAP: $2.3 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
1151.6	1359.6	1506.3	1417.8	1676.8	1512.6	1558.7	1619.8	1547.0	1618.5	*1475*	*1575*	Revenues ($mill)	*1825*
37.8	47.2	75.1	38.5	73.6	87.1	92.4	100.2	78.2	111.1	*120*	*125*	Net Profit ($mill)	*145*
36.4%	35.4%	35.9%	38.7%	38.3%	34.3%	35.0%	35.4%	34.4%	36.0%	*36.5%*	*36.5%*	Income Tax Rate	*36.5%*
3.7%	3.6%	3.9%	22.4%	14.0%	4.2%	4.0%	5.2%	8.3%	8.8%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*8.0%*
56.5%	58.0%	53.7%	41.0%	48.1%	50.9%	51.6%	51.4%	50.8%	51.4%	*50.0%*	*49.0%*	Long-Term Debt Ratio	*51.0%*
41.9%	40.6%	46.3%	59.0%	51.9%	49.1%	48.4%	48.6%	49.2%	48.6%	*50.0%*	*51.0%*	Common Equity Ratio	*49.0%*
1796.2	1900.8	1980.1	1548.9	1919.5	2139.0	2325.3	2439.9	2561.2	2669.7	*2990*	*3070*	Total Capital ($mill)	*3525*
1956.1	2126.4	2215.0	2351.3	2492.2	2607.0	2714.2	2860.8	3023.7	3202.4	*3520*	*3720*	Net Plant ($mill)	*4275*
4.3%	4.8%	6.1%	5.2%	5.8%	5.5%	5.4%	5.5%	4.3%	5.4%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
4.8%	5.9%	8.2%	4.2%	7.4%	8.3%	8.2%	8.5%	6.2%	8.6%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
4.7%	5.9%	8.0%	4.2%	7.4%	8.3%	8.2%	8.5%	6.2%	8.6%	*8.0%*	*8.0%*	Return on Com Equity E	*8.5%*
1.4%	2.4%	4.9%	.8%	3.7%	4.1%	3.3%	3.1%	.8%	2.9%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
72%	60%	40%	82%	50%	51%	60%	64%	88%	66%	*65%*	*65%*	All Div'ds to Net Prof	*66%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+2.0	-1.8	+.4
Avg. Indust. Use (MWH)	1556	1505	1428
Avg. Indust. Revs. per KWH (¢)	5.71	5.69	5.74
Capacity at Peak (Mw)	2923	3060	2767
Peak Load, Winter (Mw) F	2381	2485	2223
Annual Load Factor (%)	61.0	58.0	59.0
% Change Customers (yr-end)	+.4	+.6	+1.1
Fixed Charge Cov. (%)	318	245	308

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-7.0%	-1.5%	*1.0%*
"Cash Flow"	4.5%	1.0%	*5.0%*
Earnings	5.5%	6.5%	*5.5%*
Dividends	9.0%	13.5%	*4.5%*
Book Value	3.5%	3.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	476.6	360.6	343.7	438.9	1619.8
2012	452.3	343.6	340.6	410.5	1547.0
2013	482.9	352.0	335.9	447.7	1618.5
2014	446.6	312.6	301.6	*414.2*	*1475*
2015	*490*	*335*	*325*	*425*	*1575*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.73	.39	.18	.42	1.72
2012	.65	.31	.10	.26	1.32
2013	.71	.43	.19	.53	1.85
2014	.79	.43	.16	*.57*	*1.95*
2015	*.85*	*.45*	*.15*	*.55*	*2.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.275	.275	.275	.275	1.10
2012	.29	.29	.29	.29	1.16
2013	.305	.305	.305	.305	1.22
2014	.3175	.3175	.3175	.3175	1.27
2015					

BUSINESS: Avista Corporation (formerly The Washington Water Power Company) supplies electricity & gas in eastern Washington & northern Idaho. Supplies electricity to part of Alaska & gas to part of Oregon. Customers: 383,000 electric, 326,000 gas. Acq'd Alaska Electric Light and Power 7/14. Sold Ecova energy-management sub. 6/14. Electric rev. breakdown: residential, 32%; commercial, 28%; industrial, 11%; wholesale, 12%; other, 17%. Generating sources: hydro, 27%; gas, 14%; coal, 9%; wood waste, 2%; purchased, 48%. Fuel costs: 43% of revs. '13 reported deprec. rate (utility): 2.9%. Has 1,800 employees. Chairman, President & CEO: Scott L. Morris. Inc.: WA. Address: 1411 E. Mission Ave., Spokane, WA 99202-2600. Tel.: 509-489-0500. Web: www.avistacorp.com.

Avista's regulatory settlement was approved in Washington. Electric and gas rates were raised by $12.3 million (2.5%) and $8.5 million (5.6%), respectively, at the start of 2015. The order didn't address the cost of capital, but it did decouple revenues and volume. Accordingly, top-line advances will now track customer growth (currently at about 1% for electricity and gas), instead of sales changes.

Avista has reached a settlement of its gas rate case in Oregon. If approved by the state regulatory commission, rates will be raised (effective March 1st) by $5.0 million (5.1%), based on a 9.5% return on a 51% common-equity ratio.

More rate applications are probably on the way. Avista will likely file cases in Washington and Idaho for new tariffs in 2016. Alaska Electric Light and Power, which the company acquired in mid-2014, is also considering filing a petition.

We estimate that earnings will increase slightly in 2015. Avista should benefit from rate relief and a full year of income from the Alaska utility acquisition. On the other hand, a favorable swing in power costs helped Avista in Washington in 2014, and we do not assume that this will happen this year. Our 2015 earnings estimate is within the company's targeted range of $1.86-$2.06 a share.

Avista has repurchased some stock, and might buy back more. Through mid-December, the company repurchased 2.5 million shares for $79.9 million. The board authorized a buyback for up to 800,000 more shares in the first quarter of 2015. Later this year, however, Avista will need some equity, so the company expects to issue about $30 million. The company's financing needs also include about $100 million of long-term debt.

We expect a dividend increase this quarter. That has been the pattern in recent years. We estimate that the board of directors will boost the annual payout by $0.05 a share (3.9%). Avista is targeting yearly dividend growth of 4%-5%.

Avista stock offers a dividend yield that is slightly above the utility mean. Like several utility stocks, the recent price is above the upper end of our 2017-2019 Target Price Range. Accordingly, total return potential is low.

Paul E. Debbas, CFA ***January 30, 2015***

(A) Dil. EPS. Excl. nonrec. gain (losses): '00, (27¢); '02, (9¢); '03, (3¢); '14, 9¢; gains (losses) on disc. ops.: '01, ($1.00); '02, 2¢; '03, (10¢); '14, $1.17. '13 EPS don't add due to rounding. Next egs. due late Feb. (B) Div'ds histor. paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '13: $8.08/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in WA in '15: none; in ID in '13: 9.8%; in OR in '14: 9.65%; earn. on avg. com. eq., '13: 8.7%. Reg. Clim.: WA, Avg.; ID, Above Avg. (F) Summer pk. '12.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	75

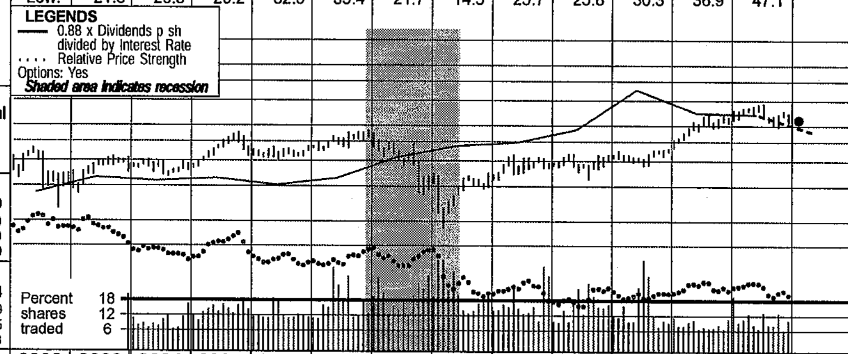
BLACK HILLS CORP. NYSE-BKH

RECENT PRICE 51.40 | P/E RATIO 18.2 (Trailing: 20.2 Median: 17.0) | RELATIVE P/E RATIO 0.99 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 1 Raised 12/12/14
SAFETY 3 Lowered 8/15/03
TECHNICAL 3 Raised 1/9/15
BETA .90 (1.00 = Market)

High:	33.5	32.5	44.6	37.9	45.4	44.0	28.0	34.5	34.8	37.0	55.1	62.1			Target Price Range		
Low:	21.8	26.5	29.2	32.5	35.4	21.7	14.5	25.7	25.8	30.3	36.9	47.1			2017	2018	2019

LEGENDS
—— 0.88 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+15%)	7%
Low	40	(-20%)	-2%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	94	85	99
to Sell	96	103	105
Hld's(000)	31901	32363	32908

Percent shares traded 18 12 6

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.0	6.9
3 yr.	75.4	73.7
5 yr.	143.6	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
31.48	37.05	69.69	57.96	15.74	35.17	34.54	41.97	19.69	18.41	26.03	32.58	33.29	28.96	26.55	28.67	*30.75*	*30.65*	Revenues per sh	*33.50*
2.72	2.88	3.68	5.27	4.93	4.26	4.46	4.81	5.04	5.29	2.95	5.41	4.88	4.01	5.59	5.93	*6.40*	*6.55*	"Cash Flow" per sh	*7.50*
1.60	1.70	2.37	3.42	2.33	1.84	1.74	2.11	2.21	2.68	.18	2.32	1.66	1.01	1.97	2.61	*2.90*	*2.85*	Earnings per sh A	*3.25*
1.00	1.04	1.08	1.12	1.16	1.20	1.24	1.28	1.32	1.37	1.40	1.42	1.44	1.46	1.48	1.52	1.56	*1.60*	Div'd Decl'd per sh B ■	*1.85*
1.18	4.89	5.79	14.07	8.65	2.80	2.80	4.18	9.24	6.92	8.51	8.90	12.04	10.03	7.90	7.97	*9.35*	*9.60*	Cap'l Spending per sh	*8.25*
9.58	10.14	11.95	18.95	19.66	21.72	22.43	22.29	23.68	25.66	27.19	27.84	28.02	27.53	27.88	29.39	*30.70*	*31.90*	Book Value per sh C	*35.75*
21.58	21.37	23.30	26.89	26.93	32.30	32.48	33.16	33.37	37.80	38.64	38.97	39.27	43.92	44.21	44.50	*44.75*	*45.00*	Common Shs Outst'g D	*45.75*
14.9	13.6	10.9	11.4	12.5	15.9	17.1	17.3	15.8	15.0	NMF	9.9	18.1	NMF	17.1	18.2	*19.0*		Avg Ann'l P/E Ratio	*15.5*
.77	.78	.71	.58	.68	.91	.90	.92	.85	.80	NMF	.66	1.15	NMF	1.09	1.03	*1.00*		Relative P/E Ratio	*.95*
4.2%	4.5%	4.2%	2.9%	4.0%	4.1%	4.2%	3.5%	3.8%	3.4%	4.2%	6.2%	4.8%	4.6%	4.4%	3.2%	2.8%		Avg Ann'l Div'd Yield	*3.7%*
						1121.7	1391.6	656.9	695.9	1005.8	1269.6	1307.3	1272.2	1173.9	1275.9	*1375*	*1380*	Revenues ($mill)	*1530*
						57.2	70.3	74.0	100.1	6.8	89.7	64.6	40.4	86.9	115.8	*130*	*130*	Net Profit ($mill)	*145*
						31.8%	33.8%	31.3%	31.3%	33.1%	30.7%	26.4%	31.1%	35.5%	34.7%	*33.5%*	*34.5%*	Income Tax Rate	*34.5%*
						.3%	1.0%	9.7%	14.8%	173.2%	20.1%	28.0%	65.0%	5.4%	2.4%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
						49.9%	47.6%	44.3%	36.8%	32.3%	48.4%	51.9%	51.4%	43.2%	51.6%	*53.0%*	*52.0%*	Long-Term Debt Ratio	*53.5%*
						49.6%	52.4%	55.7%	63.2%	67.7%	51.6%	48.1%	48.6%	56.8%	48.4%	*47.0%*	*48.0%*	Common Equity Ratio	*46.5%*
						1469.3	1409.1	1418.4	1534.2	1551.8	2100.7	2286.3	2489.7	2171.4	2704.7	*2910*	*2995*	Total Capital ($mill)	*3500*
						1445.7	1435.4	1646.4	1823.5	2022.2	2160.7	2495.4	2789.6	2742.7	2990.3	*3255*	*3520*	Net Plant ($mill)	*4150*
						5.3%	6.6%	6.8%	7.9%	1.6%	5.9%	4.4%	3.3%	5.5%	5.5%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
						7.8%	9.5%	9.4%	10.3%	.7%	8.3%	5.9%	3.3%	7.1%	8.9%	*9.5%*	*9.0%*	Return on Shr. Equity	*9.0%*
						7.8%	9.5%	9.4%	10.3%	.7%	8.3%	5.9%	3.3%	7.1%	8.9%	*9.5%*	*9.0%*	Return on Com Equity E	*9.0%*
						2.3%	3.8%	3.8%	5.1%	NMF	3.2%	.7%	NMF	1.8%	3.7%	*4.5%*	*4.0%*	Retained to Com Eq	*4.0%*
						71%	60%	59%	50%	NMF	62%	87%	NMF	75%	58%	*53%*	*55%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1566.5 mill. **Due in 5 Yrs** $459.0 mill.
LT Debt $1107.5 mill. **LT Interest** $57.6 mill.
(LT interest earned: 4.1x)
Leases, Uncapitalized Annual rentals $2.8 mill.

Pension Assets-12/13 $280.4 mill. **Oblig.** $321.4 mill.

Pfd Stock None

Common Stock 44,655,369 shs. as of 10/31/14

MARKET CAP: $2.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+1.3	+.2	+1.0
Avg. Indust. Use (MWH)	8482	8921	9740
Avg. Indust. Revs. per KWH (¢)	7.58	8.01	8.19
Capacity at Yearend (Mw)	1315	1318	NA
Peak Load, Summer (Mw)	1025	1036	988
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.3	+.8
Fixed Charge Cov. (%)	160	205	224

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-2.5%	5.5%	*3.0%*
"Cash Flow"	.5%	3.0%	*6.5%*
Earnings	-3.0%	2.0%	*9.5%*
Dividends	2.5%	1.5%	*3.5%*
Book Value	3.5%	2.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	400.8	260.7	249.5	361.2	1272.2
2012	365.8	242.4	246.8	318.9	1173.9
2013	380.7	279.8	259.9	355.5	1275.9
2014	460.2	283.2	272.1	*359.5*	*1375*
2015	*430*	*290*	*280*	*380*	*1380*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.73	.09	d.29	.44	1.01
2012	.80	.11	.38	.68	1.97
2013	.97	.69	.52	.43	2.61
2014	1.08	.44	.60	*.78*	*2.90*
2015	*1.00*	*.45*	*.60*	*.80*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.365	.365	.365	.365	1.46
2012	.37	.37	.37	.37	1.48
2013	.38	.38	.38	.38	1.52
2014	.39	.39	.39	.39	1.56
2015					

BUSINESS: Black Hills Corporation is a holding company for utilities that serve 204,000 electric customers in CO, SD, WY and MT, and 574,000 gas customers in NE, IA, KS, CO and WY. Mines coal & has a gas & oil E&P business. Acq'd Mallon Resources 3/03; Cheyenne Light 1/05; utility operations from Aquila 7/08. Discontinued telecom in '05; oil marketing in '06; gas marketing in '11. Electric revenue breakdown: res'l, 31%; comm'l, 36%; ind'l, 14%; wholesale, 11%; other, 8%. Generating sources: coal, 36%; other, 4%; purchased, 60%. Fuel costs: 41% of revs. '13 depr. rate: 3.5%. Has 1,900 empls. Chairman, President & CEO: David R. Emery. Inc.: SD. Address: P.O. Box 1400, 625 Ninth St., Rapid City, SD 57701. Tel.: 605-721-1700. Internet: www.blackhillscorp.com.

The price of Black Hills stock has been significantly affected by the price of oil in the past two years. When oil prices were high in 2013, this equity was one of the top performers in the electric utility industry. In 2014, when oil prices declined precipitously, the share price rose just 1% in a year in which most utility issues fared extremely well. Oil and natural gas prices are continuing to decline. So far, Black Hills' oil and gas exploration and production subsidiary has not announced a cutback in its drilling or capital spending plans, but this might change when the company announces earnings in early February.

We estimate that earnings will decline slightly in 2015. In early November, Black Hills put forth 2015 profit guidance of $2.90-$3.10 a share. However, this was based on higher commodity prices than are likely to occur this year. Although the company has hedged some of its expected 2015 production, there is little doubt that it will feel the effects of lower oil and gas prices. Thus, our earnings estimate of $2.85 a share is below the low end of management's guidance.

The utility received rate increases in two states. In Kansas, the commission approved a "black box" settlement (i.e., no specified return on equity) calling for a $5.2 million raise in gas rates. In Colorado, electric rates were raised by $3 million, based on a return of 9.83% on a common-equity ratio of 50.17%. Each tariff hike took effect at the start of the new year. Black Hills is awaiting a final order in its electric rate case in South Dakota, in which the utility sought an increase of $14.6 million, based on a 10.25% return on equity.

We expect a dividend increase in the current quarter. A first-period hike in the disbursement has been the practice of the board of directors for many years. We estimate that the board will boost the quarterly dividend by a cent a share (2.6%). The company's payout ratio is low enough to allow for an increase, despite the possibility of lower earnings in 2015.

This timely stock has a dividend yield that is a cut below the utility mean. It does not stand out for its 3- to 5-year total return potential.

Paul E. Debbas, CFA *January 30, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '05, (99¢); '08, ($1.55); '09, (28¢); '10, 10¢; '12, 4¢ net; gains (losses) on disc. ops.: '05, (7¢); '06, 21¢; '07, (4¢); '08, $4.12; '09, 7¢; '11, 23¢; '12, (16¢). '11, '12 EPS don't add due to chng. in shs. or rounding. Next egs. due early Feb. (B) Div'ds paid early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '13: $11.12/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in SD in '13: none specified; in CO in '15: 9.83%; earned on avg. com. eq., '13: 9.1%. Regul. Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	40

CMS ENERGY CORP. NYSE-CMS

RECENT PRICE 33.08 | P/E RATIO 17.6 (Trailing: 19.0 / Median: 15.0) | RELATIVE P/E RATIO 0.96 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Lowered 12/5/14
SAFETY 2 Raised 3/21/14
TECHNICAL 3 Raised 3/20/15
BETA .75 (1.00 = Market)

High:	10.6	16.8	17.0	19.5	17.5	16.1	19.3	22.4	25.0	30.0	36.9	38.7
Low:	7.8	9.7	12.1	15.0	8.3	10.0	14.1	17.0	21.1	24.6	26.0	32.9

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

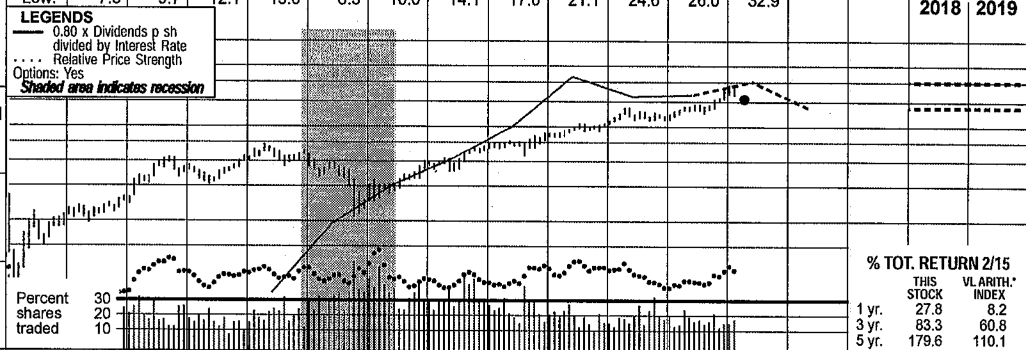
	Price	Gain	Ann'l Total Return
High	40	(+20%)	9%
Low	30	(-10%)	2%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	4	0	1	0	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	177	174	197
to Sell	187	196	184
Hld's(000)	234703	237560	237611



% TOT. RETURN 2/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.8	8.2
3 yr.	83.3	60.8
5 yr.	179.6	110.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
52.59	74.24	72.16	60.28	34.21	28.06	28.52	30.57	28.95	30.13	27.23	25.77	25.59	23.90	24.68	26.09	*25.65*	*26.00*	Revenues per sh	*28.50*
7.87	7.61	5.24	d.09	2.39	2.87	3.43	3.22	3.08	3.88	3.47	3.70	3.65	3.82	4.06	4.22	*4.40*	*4.65*	"Cash Flow" per sh	*5.50*
2.85	2.53	1.27	d2.99	d.29	.74	1.10	.64	.64	1.23	.93	1.33	1.45	1.53	1.66	1.74	*1.88*	*2.00*	Earnings per sh A	*2.25*
1.39	1.46	1.46	1.09	--	--	--	--	.20	.36	.50	.66	.84	.96	1.02	1.08	*1.16*	*1.24*	Div'd Decl'd per sh B ■	*1.50*
9.69	8.51	9.49	5.18	3.32	2.69	2.69	3.01	5.61	3.50	3.59	3.29	3.47	4.65	4.98	5.73	*5.75*	*5.60*	Cap'l Spending per sh	*5.50*
21.17	19.48	14.21	7.86	9.84	10.63	10.53	10.03	9.46	10.88	11.42	11.19	11.92	12.09	12.98	13.34	*14.15*	*15.05*	Book Value per sh C	*17.75*
116.04	121.20	132.99	144.10	161.13	195.00	220.50	222.78	225.15	226.41	227.89	249.60	254.10	264.10	266.10	275.20	*277.00*	*279.00*	Common Shs Outst'g D	*285.00*
13.9	9.6	20.8	--	--	12.4	12.6	22.2	26.8	10.9	13.6	12.5	13.6	15.1	16.3	17.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.79	.62	1.07	--	--	.66	.67	1.20	1.42	.66	.91	.80	.85	.96	.92	.92	*Value Line*		Relative P/E Ratio	*.95*
3.5%	6.0%	5.5%	7.5%	--	--	--	--	1.2%	2.7%	4.0%	4.0%	4.3%	4.2%	3.8%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 12/31/14
Total Debt $8739 mill. **Due in 5 Yrs** $4047 mill.
LT Debt $8139 mill. **LT Interest** $371 mill.
Incl. $123 mill. capitalized leases.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $25 mill.
Pension Assets-12/14 $1979 mill.
Oblig. $2547 mill.
Pfd Stock $37 mill. **Pfd Div'd** $2 mill.
Incl. 373,148 shs. $4.50 $100 par, cum., callable at $110.00.
Common Stock 275,200,000 shs.

MARKET CAP: $9.1 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
6288.0	6810.0	6519.0	6821.0	6205.0	6432.0	6503.0	6312.0	6566.0	7179.0	*7100*	*7250*	Revenues ($mill)	*8100*
247.0	158.0	168.0	300.0	231.0	356.0	384.0	413.0	454.0	479.0	*530*	*570*	Net Profit ($mill)	*690*
25.6%	--	37.6%	31.6%	34.6%	38.1%	36.8%	39.4%	39.9%	34.3%	*39.5%*	*39.5%*	Income Tax Rate	*39.5%*
15.4%	6.3%	3.6%	1.3%	13.0%	2.2%	2.6%	2.9%	2.0%	2.3%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
73.5%	71.7%	70.5%	69.4%	67.9%	70.1%	66.9%	67.9%	67.5%	68.7%	*68.0%*	*67.0%*	Long-Term Debt Ratio	*65.5%*
23.4%	24.9%	25.9%	27.4%	29.0%	29.5%	32.6%	31.6%	32.2%	31.0%	*32.0%*	*32.5%*	Common Equity Ratio	*34.5%*
9913.0	8961.0	8212.0	8993.0	8977.0	9473.0	9279.0	10101	10730	11846	*12300*	*12825*	Total Capital ($mill)	*14800*
7845.0	7976.0	8728.0	9190.0	9682.0	10069	10633	11551	12246	13412	*14325*	*15150*	Net Plant ($mill)	*17400*
5.0%	4.5%	4.5%	5.4%	4.7%	5.8%	6.3%	5.9%	6.0%	5.7%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
9.4%	6.2%	6.9%	10.9%	8.0%	12.5%	12.5%	12.8%	13.0%	12.9%	*13.5%*	*13.5%*	Return on Shr. Equity	*13.5%*
9.9%	6.4%	7.2%	11.7%	8.5%	12.5%	12.6%	12.9%	13.1%	13.0%	*13.5%*	*13.5%*	Return on Com Equity E	*13.5%*
9.9%	6.4%	5.1%	8.4%	4.1%	6.9%	5.6%	5.0%	5.2%	5.0%	*5.5%*	*5.5%*	Retained to Com Eq	*5.0%*
6%	10%	35%	31%	54%	46%	55%	61%	60%	62%	*61%*	*61%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	+.6	-3.1	+1.9
Avg. Indust. Use (MWH)	1113	1000	NA
Avg. Indust. Revs. per KWH (¢)	8.06	8.93	8.79
Capacity at Peak (Mw)	8607	8603	NA
Peak Load, Summer (Mw)	9006	8509	NA
Annual Load Factor (%)	48.7	52.5	NA
% Change Customers (yr-end)	--	+.1	--
Fixed Charge Cov. (%)	268	282	278

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-5.0%	-3.0%	2.5%
"Cash Flow"	9.0%	3.0%	5.5%
Earnings	--	12.0%	5.5%
Dividends	--	23.5%	6.5%
Book Value	3.0%	4.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1802	1333	1507	1670	6312.0
2013	1979	1406	1445	1736	6566.0
2014	2523	1468	1430	1758	7179.0
2015	*2300*	*1500*	*1500*	*1800*	*7100*
2016	*2300*	*1550*	*1550*	*1850*	*7250*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.36	.37	.55	.25	1.53
2013	.53	.29	.46	.37	1.66
2014	.75	.30	.34	.35	1.74
2015	*.68*	*.40*	*.45*	*.35*	*1.88*
2016	*.60*	*.45*	*.55*	*.40*	*2.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.21	.21	.21	.21	.84
2012	.24	.24	.24	.24	.96
2013	.255	.255	.255	.255	1.02
2014	.27	.27	.27	.27	1.08
2015	.29				

BUSINESS: CMS Energy Corporation is a holding company for Consumers Energy, which supplies electricity and gas to lower Michigan (excluding Detroit). Has 1.8 million electric, 1.7 million gas customers. Has 1,034 megawatts of nonregulated generating capacity. Sold Palisades nuclear plant in '07. Electric revenue breakdown: residential, 43%; commercial, 31%; industrial, 19%; other, 7%. Generating sources: coal, 44%; gas, 6%; other, 1%; purchased, 49%. Fuel costs: 54% of revenues. '14 reported deprec. rates: 3.5% electric, 2.8% gas, 7.7% other. Has 7,700 employees. Chairman: David W. Joos. President & CEO: John G. Russell. Incorporated: Michigan. Address: One Energy Plaza, Jackson, Michigan 49201. Tel.: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy's utility subsidiary has received a gas rate increase. Consumers Energy had filed for a tariff hike of $88 million, based on a return on equity of 10.7%. The utility reached a settlement calling for a $45 million raise, based on a 10.3% ROE. The Michigan Public Service Commission (MPSC) approved the settlement in late January.

An electric rate case is pending. Consumers Energy is seeking an increase of $163 million, based on a 10.7% ROE. Under Michigan regulatory law, the utility will self-implement a rate hike in mid-2015, and the MPSC's final order is due in late 2015. This will enable Consumers Energy to place a 540-megawatt gas-fired generating plant, which it has agreed to purchase for $155 million, in the rate base. The transaction is scheduled to close in late 2015.

We expect CMS Energy to continue to produce steady earnings growth in 2015 and 2016. The company should benefit from rate relief, reductions in operating and maintenance expenses, and moderate volume growth. Our 2015 profit estimate is within management's typically narrow range of $1.86-$1.89 a share. CMS' goal is for annual earnings growth of 5%-7%, and our 2016 forecast of $2.00 a share would produce an increase within this range.

The board of directors raised the dividend in the first quarter. The board boosted the quarterly payout by $0.02 a share (7.4%). We project continued good dividend growth through the 2018-2020 period. CMS Energy is targeting a payout ratio of 60%-70%.

Finances are adequate. Consistent earnings growth is a plus. The company's cash flow is stronger than our "cash flow" figures (which do not include deferred taxes) suggest. On the other hand, the common-equity ratio is subpar due to debt that is held at the parent level, and the fixed-charge coverage is a bit below the industry norm. CMS Energy merits a Financial Strength rating of B++.

CMS Energy's strengths are adequately reflected in the stock's quotation. This issue does not stand out among utilities for its dividend yield. Its 3- to 5-year total return potential is unspectacular.

Paul E. Debbas, CFA *March 20, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '05, ($1.61); '06, ($1.08); '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; '12, (14¢); gains (losses) on disc. ops.: '05, 7¢; '06, 3¢; '07, (40¢); '09, 8¢; '10, (8¢); '11, 1¢; '12, 3¢. '13 EPS don't add due to rounding. Next earnings report due late Apr. (B) Div'ds historically paid late Feb., May, Aug., & Nov. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '14: $7.11/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '15: 10.3%; earned on avg. com. eq., '14: 13.4%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	75

CON. EDISON NYSE-ED

RECENT PRICE **67.00** | P/E RATIO **17.2** (Trailing: 16.1 / Median: 15.0) | RELATIVE P/E RATIO **0.93** | DIV'D YLD **3.9%** | VALUE LINE

TIMELINESS	4 Lowered 12/5/14
SAFETY	1 New 7/27/90
TECHNICAL	5 Lowered 2/20/15
BETA .60 (1.00 = Market)	

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	45.6	49.3	49.3	52.9	49.3	46.3	51.0	62.7	66.0	64.0	68.9	72.3		
Low:	37.2	41.1	41.2	43.1	34.1	32.6	41.5	48.6	53.6	54.2	52.2	65.4		

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

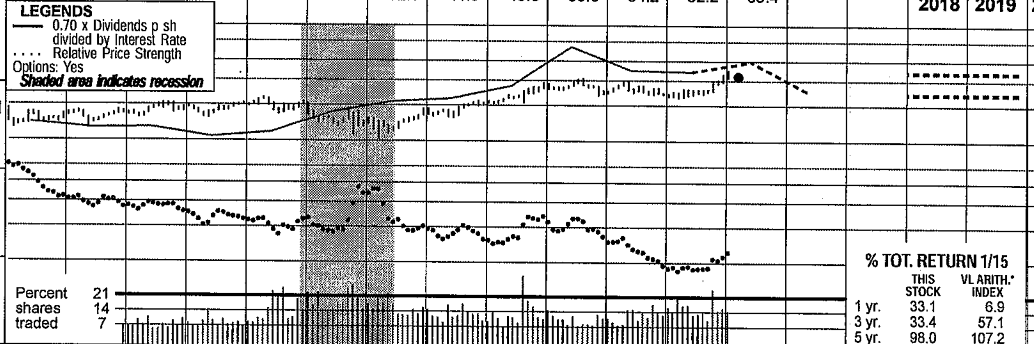
	Price	Gain	Ann'l Total Return
High	70	(+5%)	5%
Low	55	(-20%)	Nil

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	1	0	0	1	0	0	2	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	2	0	1

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	309	306	291
to Sell	249	262	252
Hld's(000)	141570	144306	146934



% TOT. RETURN 1/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	33.1	6.9
3 yr.	33.4	57.1
5 yr.	98.0	107.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
35.04	44.48	45.41	39.65	43.51	40.24	47.66	47.14	48.23	49.62	46.36	45.69	44.17	41.62	42.27	44.35	44.70	46.10	Revenues per sh	50.25
5.74	5.51	5.70	5.44	5.12	4.54	5.27	5.28	5.77	5.99	5.86	6.24	6.61	7.15	7.45	7.65	8.00	8.40	"Cash Flow" per sh	9.50
3.13	2.74	3.21	3.13	2.83	2.32	2.99	2.95	3.48	3.36	3.14	3.47	3.57	3.86	3.93	3.90	3.95	4.10	Earnings per sh A	4.50
2.14	2.18	2.20	2.22	2.24	2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	2.42	2.46	2.52	2.60	2.68	Div'd Decl'd per sh B ■	2.90
3.17	4.52	5.20	5.68	5.72	5.60	6.59	7.17	7.09	8.50	7.80	6.96	6.72	7.06	8.67	9.70	10.25	9.80	Cap'l Spending per sh	9.50
25.31	25.81	26.71	27.68	28.44	29.09	29.80	31.09	32.58	35.43	36.46	37.93	39.05	40.53	41.81	43.25	44.65	46.10	Book Value per sh C	51.00
213.81	212.03	212.15	213.93	225.84	242.51	245.29	257.46	272.02	273.72	281.12	291.62	292.89	292.87	292.87	293.00	293.00	293.00	Common Shs Outst'g D	293.00
14.0	12.0	12.0	13.3	14.3	18.2	15.1	15.5	13.8	12.3	12.5	13.3	15.1	15.4	14.7	14.8	Bold figures are		Avg Ann'l P/E Ratio	14.0
.80	.78	.61	.73	.82	.96	.80	.84	.73	.74	.83	.85	.95	.98	.83	.75	Value Line		Relative P/E Ratio	.90
4.9%	6.6%	5.7%	5.3%	5.5%	5.3%	5.0%	5.0%	4.8%	5.7%	6.0%	5.2%	4.5%	4.1%	4.3%	4.4%	estimates		Avg Ann'l Div'd Yield	4.6%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $12620 mill. **Due in 5 Yrs** $4424 mill.
LT Debt $10985 mill. **LT Interest** $538 mill.
(LT interest earned: 4.2x)

Leases, Uncapitalized Annual rentals $17 mill.

Pension Assets-12/13 $10755 mill. **Oblig.** $12197 mill.

Pfd Stock None

Common Stock 292,887,896 shs. as of 10/31/14
MARKET CAP: $20 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
11690	12137	13120	13583	13032	13325	12938	12188	12381	13000	13100	13500	Revenues ($mill)	14750
719.0	749.0	936.0	933.0	868.0	992.0	1062.0	1141.0	1157.0	1145	1170	1215	Net Profit ($mill)	1325
33.6%	35.2%	32.6%	36.0%	34.2%	36.0%	36.1%	34.5%	31.8%	34.0%	34.0%	34.0%	Income Tax Rate	34.0%
2.2%	1.6%	1.9%	1.7%	2.6%	2.4%	1.6%	.5%	.5%	1.0%	1.0%	Nil	AFUDC % to Net Profit	Nil
49.6%	50.2%	45.6%	48.3%	48.5%	48.6%	46.5%	45.9%	46.1%	48.5%	48.0%	49.5%	Long-Term Debt Ratio	48.0%
49.0%	48.5%	53.1%	50.6%	50.4%	50.4%	52.5%	54.1%	53.9%	51.5%	52.0%	50.5%	Common Equity Ratio	52.0%
14921	16515	16687	19160	20330	21952	21794	21933	22735	24525	25225	26625	Total Capital ($mill)	28800
17112	18445	19914	20874	22464	23863	25093	26939	28436	30175	32000	33625	Net Plant ($mill)	37700
6.3%	6.0%	7.0%	6.2%	5.7%	5.9%	6.2%	6.5%	6.4%	6.0%	6.0%	5.5%	Return on Total Cap'l	6.0%
9.6%	9.1%	10.3%	9.4%	8.3%	8.8%	9.1%	9.6%	9.4%	9.0%	9.0%	9.0%	Return on Shr. Equity	9.0%
9.7%	9.2%	10.4%	9.5%	8.4%	8.9%	9.2%	9.6%	9.4%	9.0%	9.0%	9.0%	Return on Com Equity E	9.0%
2.6%	2.6%	3.9%	3.1%	2.5%	3.2%	3.1%	3.6%	3.6%	3.0%	3.0%	3.0%	Retained to Com Eq	3.0%
74%	73%	63%	67%	71%	65%	66%	62%	62%	65%	65%	65%	All Div'ds to Net Prof	64%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-1.4	-1.1	+.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	14788	14344	14883
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	360	382	385

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	--	-2.5%	2.5%
"Cash Flow"	2.5%	4.5%	4.5%
Earnings	2.0%	3.0%	2.5%
Dividends	1.0%	1.0%	2.5%
Book Value	4.0%	4.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3078	2771	3438	2901	12188
2013	3306	2767	3440	2868	12381
2014	3789	2911	3390	2910	13000
2015	3650	2950	3500	3000	13100
2016	3750	3050	3600	3100	13500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.94	.73	1.49	.70	3.86
2013	1.16	.49	1.49	.79	3.93
2014	1.23	.64	1.49	.54	3.90
2015	1.20	.65	1.50	.60	3.95
2016	1.20	.70	1.55	.65	4.10

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.60	.60	.60	.60	2.40
2012	.605	.605	.605	.605	2.42
2013	.615	.615	.615	.615	2.46
2014	.63	.63	.63	.63	2.52
2015	.65				

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R, acquired 7/99), which operates in New York, New Jersey, and Pennsylvania. Has 3.6 million electric, 1.2 million gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Purchases most of its power. Fuel costs: 33% of revenues. '13 reported depreciation rates: 2.8%-3.2%. Has 14,600 employees. Chairman, President & CEO: John McAvoy. Inc.: New York. Address: 4 Irving Place, New York, New York 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

Consolidated Edison's largest utility subsidiary has filed an electric rate case. Consolidated Edison Company of New York (CECONY) is seeking a rate hike of $368 million (7.2%), based on a return of 10% on a common-equity ratio of 48%. The application is driven by a need to recover spending to enhance system reliability. The utility is also asking for a higher allowed ROE. Electric rates are frozen through year-end 2015, so new tariffs won't take effect until the start of 2016. (Gas and steam rates are frozen through year-end 2016.) CECONY isn't requesting rate increases for 2017 and 2018, but would consider (through settlement talks) a plan that would provide for additional hikes of $310 million in 2017 and $156 million in 2018.

Orange and Rockland Utilities also has a rate application pending. O&R is seeking electric and gas rate hikes of $33.4 million and $40.7 million, respectively, based on a return of 9.75% on a common-equity ratio of 48%. New tariffs should take effect on November 1st.

We estimate just a slight earnings increase in 2015, but a greater advance in 2016. ConEd is benefiting from customer conversions from oil heat to gas heat, and even the steep drop in oil prices in recent months hasn't stopped this. We base our 2016 forecast on reasonable regulatory treatment for CECONY and O&R.

The board of directors has raised the dividend. The quarterly increase was $0.02 a share (3.2%). ConEd is targeting a payout ratio of 60%-70%.

The National Transportation Safety Board has yet to release its findings about an explosion of a gas pipeline in New York last March. Eight people were killed in the accident, and dozens more were injured. ConEd is facing litigation, but has insurance and has not taken a reserve. Despite the uncertainty . . .

The price of this untimely stock is up 6% so far this year. The explosion hasn't had much influence on the quotation, but investors should keep an eye on this matter. The dividend yield is slightly above the utility mean. However, with the recent price near the upper end of our 3- to 5-year Target Price Range, total return potential is low.

Paul E. Debbas, CFA *February 20, 2015*

(A) Diluted EPS. Excl. nonrec. gain (losses): '02, (11¢); '03, (45¢); '13, (32¢); '14, 9¢; gain on discontinued operations: '08, $1.01. Next earnings report due early May. (B) Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '13: $26.83/sh. (D) In millions. (E) Rate base: net orig. cost. Rate allowed on com. eq. for CECONY in '14: 9.2% elec., 9.3% gas and steam; O&R in '12 (elec.) 9.4%, in '09 (gas) 10.3%; earned on avg. com. eq., '13: 9.5%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	85

DOMINION RES. NYSE-D

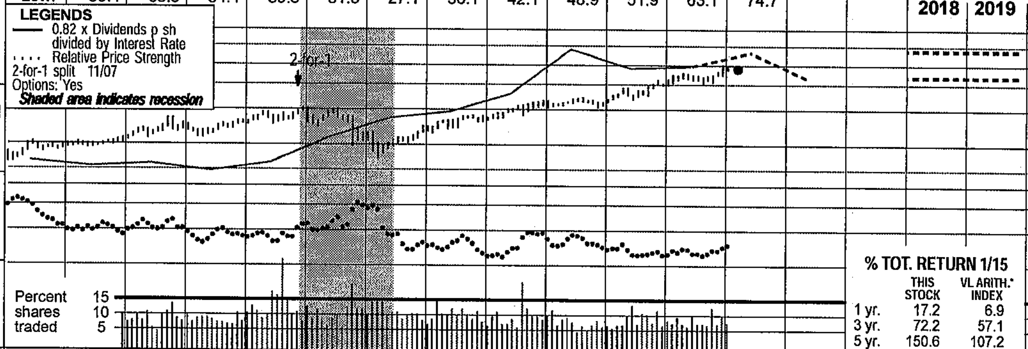
RECENT PRICE 76.66 | P/E RATIO 24.6 (Trailing: 25.2 Median: 17.0) | RELATIVE P/E RATIO 1.34 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Raised 11/15/13
SAFETY 2 Raised 9/11/98
TECHNICAL 4 Lowered 2/13/15
BETA .70 (1.00 = Market)

High:	34.4	43.5	42.2	49.4	48.5	39.8	45.1	53.6	55.6	68.0	80.9	79.9
Low:	30.4	33.3	34.4	39.8	31.3	27.1	36.1	42.1	48.9	51.9	63.1	74.7

LEGENDS
—— 0.82 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 11/07
Options: Yes
Shaded area indicates recession

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+25%)	9%
Low	70	(-10%)	2%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	5	0	0	1	0	0	2
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	350	353	325
to Sell	377	391	376
Hld's(000)	345498	344597	350385

Percent shares traded 15 10 5

% TOT. RETURN 1/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.2	6.9
3 yr.	72.2	57.1
5 yr.	150.6	107.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
14.81	18.84	19.94	16.58	18.57	20.54	25.96	23.61	27.17	27.93	25.24	26.17	25.24	22.73	22.56	21.30	20.55	20.30	Revenues per sh	21.25
3.68	3.71	3.92	4.45	3.97	4.18	3.70	4.91	5.08	5.07	4.82	5.11	5.04	5.24	5.47	5.70	6.40	6.60	"Cash Flow" per sh	8.25
1.50	1.25	1.49	2.41	1.96	2.13	1.50	2.40	2.13	3.04	2.64	2.89	2.76	2.75	3.09	3.05	3.55	3.75	Earnings per sh A	4.75
1.29	1.29	1.29	1.29	1.29	1.30	1.34	1.38	1.46	1.58	1.75	1.83	1.97	2.11	2.25	2.40	2.59	2.80	Div'd Decl'd per sh B ■	3.50
2.16	2.82	2.31	2.17	5.20	3.88	4.83	5.81	6.89	6.09	6.40	5.89	6.41	7.20	7.06	9.15	9.80	9.10	Cap'l Spending per sh	7.25
12.75	14.22	15.81	16.57	16.20	16.79	14.96	18.50	16.31	17.28	18.66	20.66	20.09	18.34	20.02	20.45	22.40	24.80	Book Value per sh C	28.50
372.64	491.60	529.40	616.20	650.40	680.40	695.00	698.00	576.80	583.20	599.40	580.80	569.70	576.10	581.50	584.00	596.00	618.00	Common Shs Outst'g D	630.00
14.5	19.4	20.9	12.0	15.2	15.1	24.9	16.0	20.6	13.8	12.7	14.3	17.3	18.9	19.2	23.0	Bold figures are	Value Line	Avg Ann'l P/E Ratio	17.5
.83	1.26	1.07	.66	.87	.80	1.33	.86	1.09	.83	.85	.91	1.09	1.20	1.08	1.20	estimates		Relative P/E Ratio	1.10
5.9%	5.3%	4.1%	4.4%	4.3%	4.0%	3.6%	3.6%	3.3%	3.8%	5.2%	4.4%	4.1%	4.1%	3.8%	3.4%			Avg Ann'l Div'd Yield	4.2%

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
18041	16482	15674	16290	15131	15197	14379	13093	13120	12436	12250	12550	Revenues ($mill)	13450
1050.0	1704.0	1414.0	1781.0	1585.0	1724.0	1603.0	1594.0	1806.0	1798.0	2135	2290	Net Profit ($mill)	3080
35.7%	35.5%	33.4%	37.1%	33.2%	38.6%	34.6%	36.2%	33.0%	28.1%	33.0%	32.5%	Income Tax Rate	31.0%
9.7%	7.9%	7.3%	4.9%	4.8%	5.9%	5.3%	5.7%	3.7%	7.0%	7.0%	6.0%	AFUDC % to Net Profit	4.0%
57.9%	52.9%	57.8%	59.1%	57.5%	56.3%	59.8%	60.9%	61.9%	64.5%	62.5%	60.5%	Long-Term Debt Ratio	58.0%
41.1%	46.2%	41.1%	39.8%	41.5%	42.8%	39.3%	38.2%	37.3%	35.5%	37.5%	39.5%	Common Equity Ratio	42.0%
25307	27961	22898	25290	26923	28012	29097	27676	31229	33750	35700	38875	Total Capital ($mill)	42700
28940	29382	21352	23274	25592	26713	29670	30773	32628	36270	40425	44250	Net Plant ($mill)	51700
6.1%	7.9%	8.0%	8.7%	7.5%	7.7%	7.0%	7.5%	7.3%	6.5%	7.5%	7.0%	Return on Total Cap'l	8.5%
9.9%	12.9%	14.6%	17.2%	13.9%	14.1%	13.7%	14.7%	15.2%	15.0%	16.0%	15.0%	Return on Shr. Equity	17.0%
9.9%	13.1%	14.9%	17.5%	14.0%	14.2%	13.9%	14.9%	15.4%	15.0%	16.0%	15.0%	Return on Com Equity E	17.0%
1.1%	5.6%	5.0%	8.4%	4.7%	5.3%	4.0%	3.5%	4.2%	3.0%	4.5%	4.0%	Retained to Com Eq	4.5%
89%	58%	67%	52%	67%	63%	71%	77%	73%	78%	72%	74%	All Div'ds to Net Prof	72%

CAPITAL STRUCTURE as of 6/30/14
Total Debt $24418 mill. **Due in 5 Yrs** $10058 mill.
LT Debt $20473 mill. **LT Interest** $972 mill.
(LT interest earned: 4.1x)

Leases, Uncapitalized Annual rentals $63 mill.
Pension Assets-12/13 $6113 mill. **Oblig.** $5625 mill.
Pfd Stock $134 mill. **Pfd Div'd** $8 mill.
1,340,140 shs. $4.04-$7.05, $100 liq. pref., redeemable at $101.00-$112.50/sh. Called in 3Q of '14.
Common Stock 582,667,882 shs.

MARKET CAP: $45 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-3.4	-2.3	+2.7
Avg. Indust. Use (MWH)	14823	15241	14444
Avg. Indust. Revs. per KWH (¢)	5.95	6.13	6.00
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.9	+.9
Fixed Charge Cov. (%)	318	316	339

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	2.5%	-2.0%	-1.5%
"Cash Flow"	2.5%	1.0%	6.5%
Earnings	4.0%	2.5%	7.5%
Dividends	5.0%	7.5%	7.5%
Book Value	2.0%	2.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3462	3053	3411	3167	13093
2013	3523	2980	3432	3185	13120
2014	3630	2813	3050	2943	12436
2015	3350	2800	3100	3000	12250
2016	3500	2850	3150	3050	12550

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.86	.48	.80	.61	2.75
2013	.86	.47	1.02	.74	3.09
2014	1.03	.60	.95	.46	3.05
2015	.90	.70	1.05	.90	3.55
2016	.95	.75	1.10	.95	3.75

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.4925	.4925	.4925	.4925	1.97
2012	.5275	.5275	.5275	.5275	2.11
2013	.5625	.5625	.5625	.5625	2.25
2014	.60	.60	.60	.60	2.40
2015	.6475				

BUSINESS: Dominion Resources, Inc. is a holding company for Virginia Power & North Carolina Power, which serve 2.5 mill. customers in Virginia & northeastern North Carolina. Acq'd Consolidated Natural Gas (1.3 mill. customers in Ohio & West Virginia) 1/00. Nonutility operations include independent power production. Owns 68.5% of Dominion Midstream Partners. Elec. rev. breakdown: residential, 46%; commercial, 33%; industrial, 7%; other, 14%. Generating sources: nuclear, 33%; coal, 29%; gas, 16%; other, 1%; purch., 21%. Fuel costs: 41% of revs. '13 reported depr. rates: 2.4%-3.8%. Has 14,500 employees. Chairman, Pres. & CEO: Thomas F. Farrell II. Inc.: VA. Address: 120 Tredegar St., P.O. Box 26532, Richmond, VA 23261-6532. Tel.: 804-819-2000. Internet: www.dom.com.

Significant investments in most of Dominion Resources' lines of business should drive earnings growth through the end of the decade. The company's regulated utility subsidiary, Virginia Power, is spending money on gas-fired and solar generation; electric transmission; moving some distribution lines underground; substation security; and hooking up additional customers. Some 75% of its spending is recoverable via "riders" on customers' bills, obviating the need for a general rate case. Dominion Energy, which is involved in midstream gas and gas distribution, is benefiting from gas production in the Marcellus and Utica shale regions. The company also has a joint venture in a (primarily) fee-based business that serves producers in these regions.

Our 2015 earnings estimate is near the low end of the company's guidance of $3.50-$3.85 a share. In most years, Dominion has expenses that we include in our presentation, even though the company excludes them from its definition of operating earnings. The fourth quarter of 2014, which includes charges totaling $0.42 a share for the early retirement of debt and future ash pond closure costs, is such an example. We forecast an earnings increase in 2016 in line with Dominion's near-term target of 5%-6% yearly growth.

Dominion Midstream Partners should be a good source of cash for Dominion. This master limited partnership had an initial public offering last fall. Dominion plans to drop down gas assets to Dominion Midstream, including a gas pipeline in South Carolina the company bought this quarter for $493 million. Dominion is also building a gas pipeline for $500 million and has a 45% stake in a $4.5 billion-$5.0 billion proposed pipeline. But the company's largest single investment is a project to convert a natural gas liquids terminal from an import to an export facility. All told, Dominion Midstream expects to increase its annual distributions by a whopping 22% through 2020.

The board of directors has increased the annual dividend by $0.19 a share (7.9%). Dominion is targeting annual dividend growth of 8% through 2020. The yield is average for a utility, but 3- to 5-year total return potential is modest.

Paul E. Debbas, CFA *February 20, 2015*

(A) Dil. egs. Excl. nonrec. gains (losses): '01, (42¢); '03, ($1.46); '04, (22¢); '06, (18¢); '07, $1.67; '08, 12¢; '09, (47¢); '10, $2.18; '11, (7¢); '12, ($1.70); '14, (76¢); losses from disc. ops.: '06, 26¢; '07, 1¢; '10, 26¢; '12, 4¢; '13, 16¢. '14 EPS don't add due to rounding. Next egs. due late Apr. (B) Div'ds histor. paid in mid-Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '13: $8.38/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost, adj. Rate all'd on com. eq. in '11: 10.9%; earned on avg. com. eq., '13: 16.0%. Regul. Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	75

DUKE ENERGY NYSE-DUK

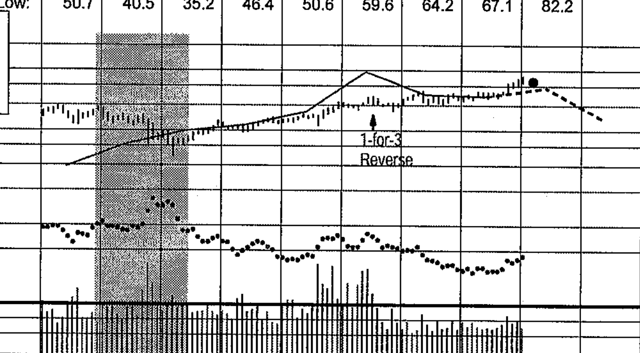
RECENT PRICE 84.18 | P/E RATIO 19.3 (Trailing: 20.3 / Median: NMF) | RELATIVE P/E RATIO 1.05 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 4 Lowered 12/5/14
SAFETY 2 New 6/1/07
TECHNICAL 5 Lowered 2/20/15
BETA .60 (1.00 = Market)

High:	63.9	61.8	53.8	55.8	66.4	71.1	75.5	87.3	90.0
Low:	50.7	40.5	35.2	46.4	50.6	59.6	64.2	67.1	82.2

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.56 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
1-for-3 Rev split 7/12
Options: Yes
Shaded area indicates recession



128, 96, 80, 64, 48, 40, 32, 24, 16, 12

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+5%)	6%
Low	65	(-25%)	-1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	0	0
to Sell	2	1	6	1	1	3	0	0	4

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	435	434	431
to Sell	470	441	423
Hld's(000)	379686	386233	392694

Percent shares traded 15 / 10 / 5

% TOT. RETURN 1/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	28.8	6.9
3 yr.	55.9	57.1
5 yr.	124.3	107.2

Duke Energy Corporation, in its current configuration, began trading on January 3, 2007, the day after it spun off its midstream gas operations into a new company, Spectra Energy (NYSE: SE). Duke Energy shareholders received half a share of Spectra Energy for each Duke share held. In July of 2012, Duke acquired Progress Energy and effected a 1-for-3 reverse split. Data for the "old" Duke are not shown because they are not comparable.

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
--	25.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	**33.95**	**34.45**	**35.85**	Revenues per sh	**40.50**
--	7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	**8.85**	**9.25**	**9.65**	"Cash Flow" per sh	**10.75**
--	2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	**4.15**	**4.50**	**4.75**	Earnings per sh A	**5.50**
--	--	2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	**3.21**	**3.27**	Div'd Decl'd per sh B ■	**3.55**
--	8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	**8.45**	**10.50**	**11.55**	Cap'l Spending per sh	**11.25**
--	62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	**58.25**	**59.50**	**60.95**	Book Value per sh C	**66.00**
--	418.96	420.62	423.96	436.29	442.96	445.29	704.00	706.00	**707.00**	**708.00**	**709.00**	Common Shs Outst'g D	**712.00**
--	--	16.1	17.3	13.3	12.7	13.8	17.5	17.4	**17.8**	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**14.5**
--	--	.85	1.04	.89	.81	.87	1.11	.98	**.95**	*estimates*		Relative P/E Ratio	**.90**
--	--	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%			Avg Ann'l Div'd Yield	**4.5%**
--	10607	12720	13207	12731	14272	14529	19624	24598	**24000**	**24400**	**25400**	Revenues ($mill)	**28800**
--	1080.0	1522.0	1279.0	1461.0	1765.0	1839.0	2136.0	2813.0	**2955**	**3205**	**3390**	Net Profit ($mill)	**3870**
--	29.4%	31.9%	32.5%	34.4%	32.6%	31.3%	30.2%	32.6%	**32.5%**	**34.5%**	**34.5%**	Income Tax Rate	**34.5%**
--	6.9%	7.2%	16.0%	17.5%	22.7%	23.2%	22.3%	8.8%	**7.0%**	**9.0%**	**9.0%**	AFUDC % to Net Profit	**8.0%**
--	41.0%	30.9%	38.7%	42.6%	44.3%	45.1%	47.0%	48.0%	**49.5%**	**50.5%**	**51.0%**	Long-Term Debt Ratio	**53.0%**
--	59.0%	69.1%	61.3%	57.4%	55.7%	54.9%	52.9%	52.0%	**50.5%**	**49.5%**	**49.0%**	Common Equity Ratio	**47.0%**
--	44220	30697	34238	37863	40457	41451	77307	79482	**81500**	**84900**	**88475**	Total Capital ($mill)	**100100**
--	41447	31110	34036	37950	40344	42661	68558	69490	**70775**	**74875**	**79600**	Net Plant ($mill)	**92700**
--	3.1%	6.0%	4.8%	4.9%	5.5%	5.6%	3.6%	4.6%	**4.5%**	**5.0%**	**5.0%**	Return on Total Cap'l	**5.0%**
--	4.1%	7.2%	6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	**7.0%**	**7.5%**	**8.0%**	Return on Shr. Equity	**8.0%**
--	4.1%	7.2%	6.1%	6.7%	7.8%	8.1%	5.2%	6.8%	**7.0%**	**7.5%**	**8.0%**	Return on Com Equity E	**8.0%**
--	4.1%	2.0%	.6%	1.1%	2.1%	2.2%	.9%	1.5%	**2.0%**	**2.0%**	**2.5%**	Retained to Com Eq	**3.0%**
--	--	72%	89%	84%	73%	72%	82%	78%	**75%**	**71%**	**68%**	All Div'ds to Net Prof	**65%**

CAPITAL STRUCTURE as of 9/30/14
Total Debt $41645 mill. **Due in 5 Yrs** $14077 mill.
LT Debt $38702 mill. **LT Interest** $1684 mill.
Incl. $1516 mill. capitalized leases. Incl. $1265 mill. nonrecourse LT debt of variable interest entities.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $175 mill.
Pension Assets-12/13 $8142 mill.
Oblig. $7361 mill.
Pfd Stock None
Common Stock 707,290,608 shs.
as of 11/4/14
MARKET CAP: $60 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-2.1	-2.8	+1.3
Avg. Indust. Use (MWH)	3062	2675	2687
Avg. Indust. Revs. per KWH (¢)	4.89	5.84	5.89
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.3	+.8	+.8
Fixed Charge Cov. (%)	292	263	327

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	--	2.0%	3.5%
"Cash Flow"	--	.5%	4.5%
Earnings	--	4.5%	5.0%
Dividends	--	11.5%	2.5%
Book Value	--	.5%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3630	3577	6722	5695	19624
2013	5898	5879	6709	6112	24598
2014		11971F	6395	**5634**	**24000**
2015	**5900**	**5600**	**6800**	**6100**	**24400**
2016	**6100**	**5850**	**7100**	**6350**	**25400**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.86	.99	1.01	.59	3.71
2013	.89	.74	1.40	.95	3.98
2014		2.08F	1.25	**.82**	**4.15**
2015	**1.15**	**.85**	**1.55**	**.95**	**4.50**
2016	**1.20**	**.90**	**1.65**	**1.00**	**4.75**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.735	.735	.75	.75	2.97
2012	.75	.75	.765	.765	3.03
2013	.765	.765	.78	.78	3.09
2014	.78	.78	.795	.795	3.15
2015					

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.1 mill. elec. customers in North Carolina, Florida, Indiana, South Carolina, Ohio, & Kentucky, and over 500,000 gas customers in Ohio & Kentucky. Owns independent power plants & has international ops. Acq'd Cinergy 4/06; spun off midstream gas ops. 1/07; acq'd Progress Energy 7/12. Elec. rev. breakdown: residential, 43%; commercial, 31%; industrial, 15%; other, 11%. Generating sources: coal, 36%; nuclear, 29%; gas, 21%; other, 1%; purchased, 13%. Fuel costs: 37% of revs. '13 reported deprec. rates: 2.4%-3.3%. Has 27,900 empls. Chairman: Ann Gray. Pres. & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Web: www.duke-energy.com.

The sale of Duke Energy's nonregulated generating assets has been delayed. The transaction would enable the company to receive $2.8 billion in cash for its ownership interests in 11 plants in the Midwest and its retail energy marketing business in Ohio. This operation is now treated as discontinued. However, the Federal Energy Regulatory Commission (FERC) has asked for additional information about the transaction, which will delay the closing beyond the current quarter. If the deal goes through, Duke will use the proceeds for capital spending, offsetting debt financing, or repurchasing stock. We will not reflect this until the deal closes.

FERC approved an asset purchase. Duke agreed to pay $1.2 billion for another utility's 700-megawatt stake in nuclear and coal-fired units in North Carolina. The transaction still requires the approval of state regulators and the Nuclear Regulatory Commission. It has a year-end 2016 deadline for completion.

Some other large capital projects are in various stages of development. In Florida, Duke plans to build a 1,685-mw gas-fired plant at a cost of $1.5 billion, uprate an existing facility to add 220 mw, and build or buy another plant. In South Carolina, the utility is adding 650 mw of gas-fired capacity at a cost of $600 million. In Indiana, the company is asking the state commission to approve a seven-year, $1.9 billion system modernization plan. And Duke has a 40% stake in a proposed $4.5 billion-$5.0 billion pipeline to transport gas from West Virginia to North Carolina, beginning in 2018.

Duke is reviewing its international operations. This began before oil prices plummeted and the dollar strengthened. These factors will hurt this segment's profitability, so we have cut our 2015 earnings estimate by $0.15 a share. We expect modest profit growth in 2016. Note that our estimates and projections *include* the international businesses, as well as costs that Duke is incurring to integrate Progress Energy, which it acquired in 2012.

This untimely stock's dividend yield is somewhat above average for a utility. With the recent price near the upper end of our 2018-2020 Target Price Range, total return potential is unappealing.

Paul E. Debbas, CFA ***February 20, 2015***

(A) Dil. EPS. Excl. nonrec. losses: '12, 70¢; '13, 24¢; gains (loss) on disc. ops.: '12, 6¢; '13, 2¢; '14, (81¢). '12 EPS don't add due to chg. in shs., '13 due to rounding. Next egs. report due early May. (B) Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. avail. (C) Incl. intang. In '13: $36.42/sh. (D) In mill., adj. for rev. split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in '13 in NC/SC: 10.2%; in '09 in OH: 10.63%; in '04 in IN: 10.3%; earned avg. com. eq., '13: 6.8%. Reg. Clim.: NC Avg.; SC, OH, IN Above Avg. (F) Restated 6-month total.

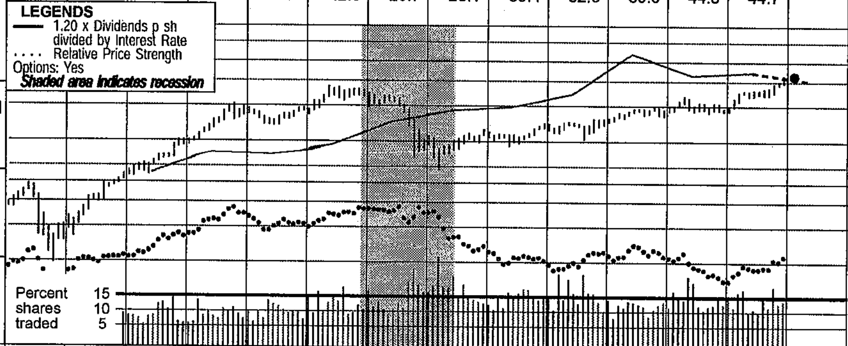
Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	75

EDISON INTERNAT'L NYSE-EIX

RECENT PRICE **68.17** | P/E RATIO **17.8** (Trailing: 17.0, Median: 12.0) | RELATIVE P/E RATIO **0.97** | DIV'D YLD **2.5%** | VALUE LINE

TIMELINESS **3** Lowered 11/7/14
SAFETY **2** Raised 5/3/13
TECHNICAL **3** Raised 1/2/15
BETA .75 (1.00 = Market)

High:	22.1	32.5	49.2	47.2	60.3	55.7	36.7	39.4	41.6	48.0	54.2	68.7
Low:	10.6	21.2	30.4	37.9	42.8	26.7	23.1	30.4	32.6	39.6	44.3	44.7



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+10%)	5%
Low	55	(-20%)	-2%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	1	6	0	3	0	0	1	0	0
to Sell	0	5	0	3	0	0	1	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	219	200	206
to Sell	231	221	217
Hld's(000)	260616	258418	260974

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	45.0	6.9
3 yr.	70.7	73.7
5 yr.	117.8	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
29.12	27.85	35.96	35.10	35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	*40.80*	*42.95*	Revenues per sh	*51.50*
6.65	7.20	d.52	4.35	4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	*9.10*	*9.20*	"Cash Flow" per sh	*11.25*
1.86	2.03	d5.84	1.30	1.82	2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	*4.00*	*3.75*	Earnings per sh A	*4.50*
1.04	1.08	.83	--	--	--	.80	1.02	1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	*1.71*	Div'd Decl'd per sh B ■	*2.25*
2.75	3.55	4.57	2.86	4.88	3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	*12.70*	*13.70*	Cap'l Spending per sh	*13.00*
14.55	15.01	7.43	10.04	13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	*33.35*	*35.30*	Book Value per sh C	*41.50*
350.55	347.21	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	*325.81*	*325.81*	Common Shs Outst'g D	*325.81*
15.1	12.9	--	10.0	7.8	7.0	NMF	11.7	13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	*14.1*		Avg Ann'l P/E Ratio	*14.5*
.79	.74	--	.51	.43	.40	NMF	.62	.70	.85	.75	.65	.66	.74	.62	.71	*.75*		Relative P/E Ratio	*.90*
3.7%	4.1%	3.9%	--	--	--	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $12186 mill. **Due in 5 Yrs** $2809 mill.
LT Debt $10133 mill. **LT Interest** $486 mill.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $1349 mill.
Pens. Assets-12/13 $3477 mill. **Oblig.** $4178 mill.
Pfd Stock $2022 mill. **Pfd Div'd** $115 mill.
4,800,198 sh. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh.; 3,250,000 sh. 5.07%, noncum., call. $100; 1,250,000 sh. 6.5%, cum., $100 liq. value; 350,000 sh. 6.25%, $1000 liq. value; 460,012 sh. 5.1%-5.75%, $2500 liq. value.
Common Stock 325,811,206 shs. **as of 10/24/14**
MARKET CAP: $22 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
10199	11852	12622	13113	14112	12374	12409	12760	11862	12581	*13300*	*14000*	Revenues ($mill)	*16750*
220.0	1132.0	1134.0	1151.0	1266.0	1115.0	1153.0	1112.0	1594.0	1344.0	*1435*	*1365*	Net Profit ($mill)	*1615*
--	26.0%	31.4%	27.3%	30.7%	33.0%	32.1%	25.7%	14.3%	25.2%	*20.0%*	*30.0%*	Income Tax Rate	*30.0%*
11.4%	4.9%	5.1%	8.2%	8.9%	10.5%	16.9%	14.8%	8.5%	7.8%	*8.0%*	*10.0%*	AFUDC % to Net Profit	*7.0%*
60.5%	54.6%	51.3%	49.1%	51.2%	49.3%	51.8%	55.3%	45.2%	45.7%	*44.5%*	*45.0%*	Long-Term Debt Ratio	*44.5%*
37.8%	40.9%	43.5%	46.0%	44.5%	46.5%	44.3%	40.6%	46.2%	46.2%	*47.0%*	*46.5%*	Common Equity Ratio	*48.0%*
15995	16167	17725	18375	21374	21185	23861	24773	20422	21516	*23225*	*24725*	Total Capital ($mill)	*28300*
13475	14469	15913	17403	18969	21966	24778	32116	30273	30455	*32950*	*35675*	Net Plant ($mill)	*43200*
4.2%	9.4%	8.6%	8.3%	7.4%	6.9%	6.3%	6.0%	8.9%	7.3%	*7.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
3.5%	15.4%	13.1%	12.3%	12.1%	10.4%	10.0%	10.0%	14.2%	11.5%	*11.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
3.5%	16.7%	14.0%	13.0%	12.8%	10.8%	10.4%	10.5%	15.9%	12.5%	*12.0%*	*11.0%*	Return on Com Equity E	*11.0%*
NMF	12.2%	10.1%	9.2%	8.6%	6.7%	6.5%	6.3%	11.4%	8.1%	*7.5%*	*6.0%*	Retained to Com Eq	*5.5%*
121%	29%	31%	33%	35%	41%	40%	43%	32%	40%	*41%*	*50%*	All Div'ds to Net Prof	*53%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.9	+2.6	-.3
Avg. Indust. Use (MWH)	736	763	791
Avg. Indust. Revs. per KWH (¢)	7.09	7.50	8.00
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	22374	21981	22534
Annual Load Factor (%)	50.7	52.7	52.1
% Change Customers (yr-end)	+.4	+.4	+.6
Fixed Charge Cov. (%)	209	308	295

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	.5%	-1.5%	*5.0%*
"Cash Flow"	6.0%	3.5%	*3.5%*
Earnings	7.5%	2.5%	*2.5%*
Dividends	--	2.5%	*9.5%*
Book Value	8.5%	3.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	2782	2983	3981	3014	12760
2012	2415	2653	3734	3060	11862
2013	2632	3046	3960	2943	12581
2014	2926	3016	4356	*3002*	*13300*
2015	*3100*	*3400*	*4300*	*3200*	*14000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.62	.54	1.31	.76	3.23
2012	.54	.55	1.09	2.39	4.55
2013	.78	.78	1.41	.81	3.78
2014	.61	1.07	1.52	*.80*	*4.00*
2015	*.75*	*.75*	*1.50*	*.75*	*3.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.32	.32	.32	.32	1.28
2012	.325	.325	.325	.325	1.30
2013	.3375	.3375	.3375	.3375	1.35
2014	.355	.355	.355	.355	1.42
2015	.4175				

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 4.9 mill. customers in a 50,000 sq. mi. area in central, coastal, and southern California (excl. Los Angeles and San Diego). Discontinued Edison Mission Energy (independent power producer) in '12. Elec. revenue breakdown: residential, 40%; commercial, 42%; industrial, 5%; other, 13%. Generating sources: gas, 7%; nuclear, 6%; coal, 5%; hydro, 3%; purchased, 79%. Fuel costs: 35% of revs. '13 reported deprec. rate: 4.2%. Has 13,700 employees. Chairman, President & CEO: Theodore F. Craver, Jr. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Internet: www.edison.com.

Edison International's board of directors rewarded the company's stockholders with a large dividend increase. The board raised the annual dividend by $0.25 a share (17.6%), payable at the end of January. The company is targeting a payout ratio of 45%-55% of the profits of its utility subsidiary, Southern California Edison.

SCE's general rate case is pending. The utility is asking for rate hikes of $82 million in 2015, $295 million in 2016, and $313 million in 2017. On the other hand, the state's Office of Ratepayer Advocates and an intervenor group are proposing a *decrease* of $680 million this year, followed by increases of $98 million in 2016 and $116 million in 2017. The ruling will be retroactive to the start of 2015. No matter what happens with the rate order . . .

Earnings will probably decline in 2015. Edison International recorded some tax benefits in 2014, thereby making the profit comparison difficult. The tax rate will probably be higher this year. We expect earnings growth to resume in 2016. The utility is benefiting from its rising rate base, which is expected to climb 7%-9% annually through 2017.

The California commission approved a regulatory settlement concerning the San Onofre nuclear plant. SCE shut the two units in 2013 due to damage stemming from the replacement of the steam generators, and took a writedown. The utility will retain 5% of any insurance recoveries and 50% of any monies it gets from the manufacturer of the steam generators. SCE is involved in a dispute, which won't likely be resolved anytime soon, with the manufacturer.

Edison International was one of the top-performing electric utility stocks in 2014. The share price rose nearly 50%, as investors responded favorably to the resolution of the uncertainties surrounding San Onofre. The dividend hike helped, too. However, even though we have raised our sights for the 3- to 5-year period, with the recent price above the midpoint of our 2017-2019 Target Price Range, total return potential (like that of most utility issues) is low. The stock's dividend yield is also about a percentage point below the industry average.

Paul E. Debbas, CFA — *January 30, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, $1.48; '03, (12¢); '04, $2.12; '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); gains (loss) from discont. ops.: '12, ($5.11); '13, 11¢; '14, 44¢. '12 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '13: $22.22/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '13: 10.45%; earned on avg. com. eq., '13: 12.5%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	65

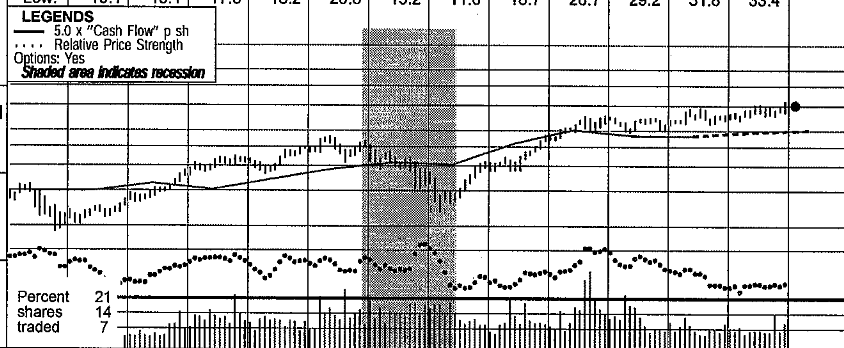
EL PASO ELECTRIC NYSE-EE

RECENT PRICE 40.28 | P/E RATIO 18.0 (Trailing: 18.4; Median: 15.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Lowered 12/5/14
SAFETY 2 Raised 5/11/07
TECHNICAL 3 Raised 11/28/14
BETA .70 (1.00 = Market)

High:	13.6	19.1	22.4	25.0	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2		Target Price Range		
Low:	10.1	13.1	17.8	18.2	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4		2017	2018	2019

LEGENDS
— 5.0 x "Cash Flow" p sh
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+10%)	6%
Low	35	(-15%)	Nil

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	1	0	2	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	83	72	69
to Sell	75	90	76
Hld's(000)	39582	39656	40115

Percent shares traded 21 / 14 / 7

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.6	6.9
3 yr.	26.6	73.7
5 yr.	120.7	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
9.99	9.96	13.70	15.40	13.91	13.97	14.95	16.70	17.75	19.43	23.15	18.85	20.61	22.97	21.26	22.11	22.85	23.35	Revenues per sh	26.75
2.34	2.79	3.21	3.43	2.99	3.00	3.27	3.05	3.44	3.86	4.16	4.07	5.15	6.05	5.66	5.65	5.90	6.05	"Cash Flow" per sh	7.25
.70	.86	1.09	1.27	.57	.64	.69	.76	1.27	1.63	1.73	1.50	2.07	2.48	2.26	2.20	2.30	2.05	Earnings per sh A	2.50
--	--	--	--	--	--	--	--	--	--	--	--	--	.66	.97	1.05	1.11	1.17	Div'd Decl'd per sh B	1.35
1.08	1.28	1.70	1.85	1.75	2.03	1.94	2.28	2.73	4.63	5.36	5.95	5.27	5.90	6.70	7.18	9.65	7.85	Cap'l Spending per sh	7.00
6.92	7.36	8.05	9.01	9.20	10.51	11.23	11.56	12.60	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.50	25.30	Book Value per sh C	28.25
60.27	57.26	51.20	49.99	49.61	47.56	47.40	48.14	46.00	45.15	44.88	43.92	42.57	39.96	40.11	40.27	40.50	40.70	Common Shs Outst'g D	41.30
12.3	9.9	10.6	11.0	23.0	18.3	22.0	26.7	16.9	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.2		Avg Ann'l P/E Ratio	15.5
.64	.56	.69	.56	1.26	1.04	1.16	1.42	.91	.81	.72	.72	.68	.79	.92	.89	.85		Relative P/E Ratio	.95
--	--	--	--	--	--	--	--	--	--	--	--	--	2.1%	3.0%	3.0%	3.0%		Avg Ann'l Div'd Yield	3.5%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1089.2 mill. **Due in 5 Yrs** $187.7 mill.
LT Debt $984.7 mill. **LT Interest** $60.6 mill.
(LT interest earned: 2.7x)

Leases, Uncapitalized Annual rentals $1.1 mill.
Pension Assets-12/13 $257.8 mill.
Oblig. $317.8 mill.

Pfd Stock None

Common Stock 40,357,982 shs.
as of 10/31/14

MARKET CAP: $1.6 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
708.6	803.9	816.5	877.4	1038.9	828.0	877.3	918.0	852.9	890.4	925	950	Revenues ($mill)	1100
33.4	36.6	61.4	74.8	77.6	66.9	90.3	103.5	90.8	88.6	95.0	85.0	Net Profit ($mill)	105
21.6%	33.7%	29.8%	31.6%	32.8%	33.1%	36.1%	34.2%	34.1%	33.0%	30.5%	33.0%	Income Tax Rate	33.0%
10.3%	15.8%	8.0%	15.9%	20.4%	24.3%	22.1%	17.6%	22.4%	24.1%	30.0%	24.0%	AFUDC % to Net Profit	19.0%
41.6%	52.3%	51.5%	49.6%	53.8%	52.7%	51.2%	51.8%	54.8%	51.4%	53.5%	56.0%	Long-Term Debt Ratio	56.5%
58.4%	47.7%	48.5%	50.4%	46.2%	47.3%	48.8%	48.2%	45.2%	48.6%	46.5%	44.0%	Common Equity Ratio	43.5%
911.8	1167.5	1195.8	1321.6	1503.9	1527.7	1660.1	1576.7	1824.5	1943.5	2145	2330	Total Capital ($mill)	2700
1283.0	1291.7	1332.2	1450.6	1595.6	1756.0	1865.8	1947.1	2102.3	2257.5	2500	2660	Net Plant ($mill)	2975
6.4%	4.9%	6.6%	7.1%	6.7%	6.0%	7.0%	8.3%	6.5%	6.1%	6.0%	5.0%	Return on Total Cap'l	5.5%
6.3%	6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.5%	8.0%	Return on Shr. Equity	9.0%
6.3%	6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	13.6%	11.0%	9.4%	9.5%	8.0%	Return on Com Equity E	9.0%
6.3%	6.6%	10.6%	11.2%	11.2%	9.3%	11.1%	10.0%	6.3%	4.9%	5.0%	3.5%	Retained to Com Eq	4.5%
--	--	--	--	--	--	--	26%	43%	47%	48%	56%	All Div'ds to Net Prof	53%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+3.1	+.7	+.4
Avg. Indust. Use (MWH)	21921	21659	21908
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1785	1765	1852
Peak Load, Summer (Mw)	1714	1688	1750
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.7	+1.5	+1.3
Fixed Charge Cov. (%)	346	302	280

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	4.5%	2.0%	3.0%
"Cash Flow"	6.5%	8.5%	4.0%
Earnings	11.0%	8.5%	1.5%
Dividends	--	--	7.0%
Book Value	8.0%	8.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	176.1	242.6	307.6	191.7	918.0
2012	168.6	228.3	267.2	188.8	852.9
2013	177.3	240.1	282.7	190.3	890.4
2014	185.5	251.8	283.6	204.1	925
2015	195	255	295	205	950

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.16	.78	1.40	.13	2.48
2012	.08	.77	1.29	.12	2.26
2013	.19	.72	1.26	.03	2.20
2014	.11	.75	1.30	.14	2.30
2015	.15	.65	1.15	.10	2.05

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	--	.22	.22	.22	.66
2012	.22	.25	.25	.25	.97
2013	.25	.265	.265	.265	1.05
2014	.265	.28	.28	.28	1.11
2015					

BUSINESS: El Paso Electric Company (EPE) provides electric service to 398,000 customers in an area of approximately 10,000 square miles in the Rio Grande valley in western Texas (68% of revenues) and southern New Mexico (19% of revenues), including El Paso, Texas and Las Cruces, New Mexico. Wholesale is 13% of revenues. Electric revenue breakdown by customer class not available. Generating sources: nuclear, 46%; gas, 34%; coal, 6%; purchased, 14%. Fuel costs: 32% of revenues. '13 reported depreciation rate: 2.6%. Has about 1,000 employees. Chairman: Michael K. Parks. CEO: Thomas V. Shockley, III. President: Mary Kipp. Inc.: Texas. Address: Stanton Tower, 100 North Stanton, El Paso, Texas 79901. Telephone: 915-543-5711. Internet: www.epelectric.com.

The effects of regulatory lag for El Paso Electric in 2015 will be greater than we had expected. The company is building four 88-megawatt gas-fired peaking units. Two are expected to be in service by the end of the current quarter. A third unit will be on line in 2016, and a fourth in late 2016 or early 2017. (The total cost is estimated at $370 million.) The utility is planning to file rate cases in New Mexico in April and in Texas in August, with new tariffs taking effect in each state in March of 2016. This means that EPE won't get any rate relief this year, but will incur costs associated with the new units. In addition, the Allowance for Funds Used During Construction (a noncash credit to income) that the company will record in 2015 will be well below the 2014 level due to the completion of the first two units. All of this is will hurt earnings this year by an estimated $0.31-$0.37 a share. There will be some positive factors, too, such as customer growth that has been at 1.4% lately, but the negative will almost certainly outweigh the positive. All told, we have cut our 2015 earnings estimate by $0.15 a share, to $2.05.

We forecast higher profits in 2016. EPE should benefit from rate relief and continued growth in its service area (see below).

The company is financing its construction budget with debt. EPE issued $150 million of 30-year debt in December, and will probably issue the same amount (although with a shorter maturity) in late 2015.

The economy of the utility's service area is in good shape. For a few years, growth was driven by the expansion of the army base at Fort Bliss. Now, other factors are helping. Some companies have announced plans for new facilities and will hire workers. Other expansions are occurring at medical facilities and at the University of Texas at El Paso. All of this should help boost the demand for power.

The stock's dividend yield is a cut below the utility average. Although we project strong dividend growth over the 3- to 5-year period, total return prospects are unspectacular, given that the recent price is well within our 2017-2019 Target Price Range.

Paul E. Debbas, CFA *January 30, 2015*

(A) Diluted earnings. Excl. nonrecurring gains (losses): '98, 6¢; '99, (38¢); '01, (4¢); '03, 81¢; '04, 4¢; '05, (2¢); '06, 13¢; '10, 24¢. '11 earnings don't add to full-year total due to rounding. Next earnings report due late Feb. (B) Initial dividend declared 4/11; payment dates in late March, June, Sept., and Dec. (C) Incl. deferred charges. In '13: $101.0 mill., $2.51/sh. (D) In millions. (E) Rate allowed on common equity in '12: none specified; earned on average common equity, '13: 10.0%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	85

EMPIRE DISTRICT NYSE-EDE

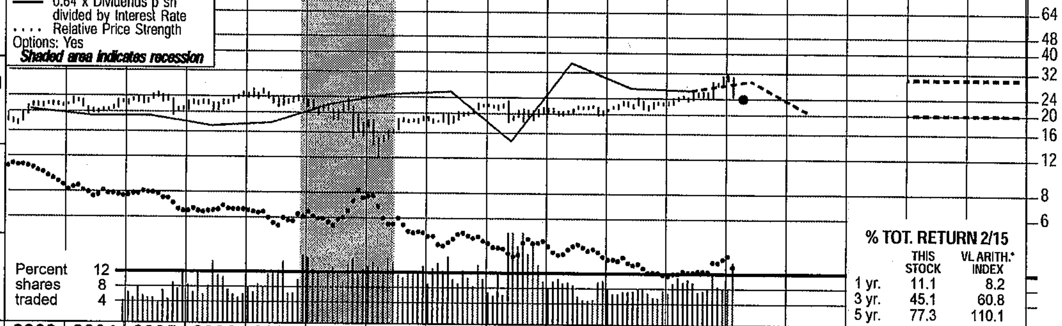
RECENT PRICE 23.96 | P/E RATIO 17.0 (Trailing: 15.5 / Median: 16.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 4 Lowered 12/5/14
SAFETY 2 Raised 3/23/12
TECHNICAL 3 Raised 3/20/15
BETA .70 (1.00 = Market)

High:	23.5	25.0	25.1	26.1	23.5	19.4	22.5	23.3	22.0	24.3	31.2	31.5
Low:	19.5	19.3	20.3	21.1	14.9	11.9	17.6	18.0	19.5	20.6	22.0	23.7

LEGENDS
— 0.64 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+25%)	10%
Low	20	(-15%)	1%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	4	0	0	0	0
to Sell	0	1	1	0	1	1	0	1	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	73	56	63
to Sell	63	69	63
Hld's(000)	20869	20897	21381

% TOT. RETURN 2/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.1	8.2
3 yr.	45.1	60.8
5 yr.	77.3	110.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
13.94	14.78	13.37	13.56	13.03	12.67	14.80	13.67	14.59	15.25	13.04	13.02	13.74	13.11	13.81	15.00	15.25	15.45	Revenues per sh	17.50
2.89	3.12	2.19	2.43	2.48	2.22	2.45	2.75	2.69	2.91	2.72	2.85	3.21	2.99	3.14	3.45	3.50	3.55	"Cash Flow" per sh	4.25
1.13	1.35	.59	1.19	1.29	.86	.92	1.41	1.09	1.17	1.18	1.17	1.31	1.32	1.48	1.55	1.40	1.45	Earnings per sh A	1.75
1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	.64	1.00	1.01	1.03	1.05	1.07	Div'd Decl'd per sh B ■ †	1.20
4.14	7.61	4.02	3.43	2.65	1.64	2.83	3.97	5.46	6.28	4.07	2.63	2.44	3.22	3.60	4.91	4.20	2.55	Cap'l Spending per sh	3.50
13.48	13.65	13.58	14.59	15.17	14.76	15.08	15.49	16.04	15.56	15.75	15.82	16.53	16.90	17.43	18.02	18.35	18.85	Book Value per sh C	20.25
17.37	17.60	19.76	22.57	24.98	25.70	26.08	30.25	33.61	33.98	38.11	41.58	41.98	42.48	43.04	43.48	44.00	44.50	Common Shs Outst'g D	47.50
21.7	17.7	33.9	16.2	15.8	24.8	24.5	15.9	21.7	17.3	14.3	16.8	15.8	15.8	15.0	16.2	Bold figures are		Avg Ann'l P/E Ratio	13.5
1.24	1.15	1.74	.88	.90	1.31	1.30	.86	1.15	1.04	.95	1.07	.99	1.01	.84	.86	Value Line		Relative P/E Ratio	.85
5.2%	5.4%	6.4%	6.6%	6.3%	6.0%	5.7%	5.7%	5.4%	6.3%	7.6%	6.5%	3.1%	4.8%	4.5%	4.1%	estimates		Avg Ann'l Div'd Yield	5.0%

CAPITAL STRUCTURE as of 12/31/14

Total Debt $847.5 mill. Due in 5 Yrs $160.6 mill.
LT Debt $803.2 mill. LT Interest $41.7 mill.
Incl. $3.9 mill. capitalized leases.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $.7 mill.
Pension Assets-12/14 $192.7 mill. Oblig. $251.9 mill.
Pfd Stock None

Common Stock 43,517,285 shs.
as of 2/2/15

MARKET CAP: $1.0 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
386.2	413.5	490.2	518.2	497.2	541.3	576.9	557.1	594.3	652.3	670	710	Revenues ($mill)	830
23.8	39.9	33.2	39.7	41.3	47.4	55.0	55.7	63.4	67.1	60.0	65.0	Net Profit ($mill)	85.0
33.4%	35.4%	30.3%	32.5%	32.5%	39.2%	38.4%	38.0%	37.1%	36.9%	37.5%	38.0%	Income Tax Rate	37.5%
2.4%	10.7%	23.1%	31.5%	34.2%	21.5%	.9%	3.5%	9.4%	14.8%	10.0%	3.0%	AFUDC % to Net Profit	6.0%
51.0%	49.7%	50.1%	53.6%	51.6%	51.3%	49.9%	49.1%	49.8%	50.6%	51.0%	52.0%	Long-Term Debt Ratio	50.0%
49.0%	50.3%	49.9%	46.4%	48.4%	48.7%	50.1%	50.9%	50.2%	49.4%	49.0%	48.0%	Common Equity Ratio	50.0%
803.3	931.0	1081.1	1140.4	1240.3	1350.7	1386.2	1409.4	1493.6	1586.5	1645	1805	Total Capital ($mill)	1925
896.0	1031.0	1178.9	1342.8	1459.0	1519.1	1563.7	1657.6	1751.9	1910.3	2000	2020	Net Plant ($mill)	2150
4.7%	5.9%	4.7%	5.2%	5.2%	5.1%	5.5%	5.4%	5.6%	5.5%	5.0%	5.0%	Return on Total Cap'l	5.5%
6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	7.5%	7.5%	Return on Shr. Equity	8.5%
6.0%	8.5%	6.2%	7.5%	6.9%	7.2%	7.9%	7.8%	8.5%	8.6%	7.5%	7.5%	Return on Com Equity E	8.5%
NMF	.8%	NMF	NMF	NMF	NMF	4.1%	1.9%	2.7%	2.9%	2.0%	2.0%	Retained to Com Eq	3.0%
NMF	90%	117%	109%	109%	110%	49%	76%	68%	66%	74%	74%	All Div'ds to Net Prof	68%

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-3.2	+1.3	+1.3
Avg. Industrial Use (MWH)	2913	2943	2981
Avg. Industrial Rev/KWH (¢)	7.66	7.93	8.21
Capacity at Peak (Mw)	1391	1377	1326
Peak Load, Summer (Mw)	1142	1080	1162
Annual Load Factor (%)	52.2	56.2	52.8
% Change Customers (avg.)	+.6	+.5	+.3
Fixed Charge Cov. (%)	314	331	334

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	.5%	-.5%	4.0%
"Cash Flow"	3.0%	3.0%	5.0%
Earnings	2.5%	5.0%	3.0%
Dividends	-2.5%	-4.5%	3.0%
Book Value	1.5%	2.0%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	137.2	131.6	159.2	129.1	557.1
2013	151.1	136.6	157.5	149.1	594.3
2014	179.7	149.8	171.5	151.3	652.3
2015	170	160	180	160	670
2016	180	170	190	170	710

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.23	.25	.60	.23	1.32
2013	.30	.27	.56	.35	1.48
2014	.48	.26	.55	.26	1.55
2015	.30	.25	.60	.25	1.40
2016	.30	.25	.63	.27	1.45

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.32	.32	--	--	.64
2012	.25	.25	.25	.25	1.00
2013	.25	.25	.25	.255	1.01
2014	.255	.255	.255	.26	1.03
2015	.26				

BUSINESS: The Empire District Electric Company supplies electricity to 169,000 customers in a 10,000 sq. mi. area in southwestern Missouri (90% of retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (2%). Acquired Missouri Gas (44,000 customers) 6/06. Supplies water service (4,000 customers) and has a small fiber-optics operation. Elec. rev. breakdown: residential, 45%; commercial, 32%; industrial, 16%; other, 7%. Generating sources: coal, 47%; gas, 27%; hydro, 1%; purch., 25%. Fuel costs: 37% of revenues. '14 reported depr. rate: 3.0%. Has about 750 employees. Chairman: D. Randy Laney. President & CEO: Bradley P. Beecher. Inc.: KS. Address: 602 S. Joplin Ave., P.O. Box 127, Joplin, MO 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

Empire District Electric is awaiting an order on its electric rate application. The utility is seeking a rate hike of $24.3 million (5.5%), based on a 10.15% return on a 51.45% common-equity ratio. The single-biggest driver of the rate case is the need to place an environmental upgrade to the Asbury coal-fired plant in the rate base. This project was completed in December at a cost of $121 million. Empire District also wants to recover higher property taxes and the cost of a maintenance contract for Unit 12 of the Riverton gas-fired plant. In addition, the utility proposes to recover changes in transmission costs through its fuel adjustment clause. New tariffs should take effect by July, unless Empire District reaches a settlement that would allow for new rates sooner. The company has asked the Kansas and Arkansas commissions to allow it to recover the cost of this project through a rider on customers' bills, and plans to make a similar request in Oklahoma.

Due to the effects of regulatory lag, earnings will probably decline in 2015. Empire District is already booking higher depreciation expense and property taxes associated with the Asbury upgrade, but won't receive rate relief for a few more months. We underestimated the effects of regulatory lag, and have cut our 2015 earnings estimate by $0.10 a share, to $1.40. Our revised estimate is within the company's targeted range of $1.30-$1.45.

We forecast only a partial profit recovery in 2016, due to more regulatory lag. Empire District is expanding Riverton 12's capacity by 100 megawatts at an expected cost of $165 million-$175 million. The utility plans to file another rate case in Missouri once the current one is concluded, but rate relief won't come until after the project goes into service in mid-2016.

Empire District stock is untimely, and has fallen nearly 20% so far in 2015. We think the recent decline is merely a correction. For a while, the price rose above $30 a share, possibly indicating that the company was viewed as a takeover candidate. The dividend yield is a cut above the utility average, but total return potential to 2018-2020 is low, even after the pullback.

Paul E. Debbas, CFA *March 20, 2015*

(A) Diluted earnings. Excl. loss from discontinued operations: '06, 2¢. '12 EPS don't add due to rounding. Next earnings report due late April. (B) Div'ds historically paid in mid-Mar., June, Sept. and Dec. Div'ds suspended 3Q '11, reinstated 1Q '12. ■ Div'd reinvestment plan avail. (3% discount). † Shareholder investment plan avail. (C) Incl. intangibles. In '14: $5.93/sh. (D) In mill. (E) Rate base: Deprec. orig. cost. Rate allowed on com. eq. in MO in '13: none specified; earned on avg. com. eq., '14: 8.7%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	85

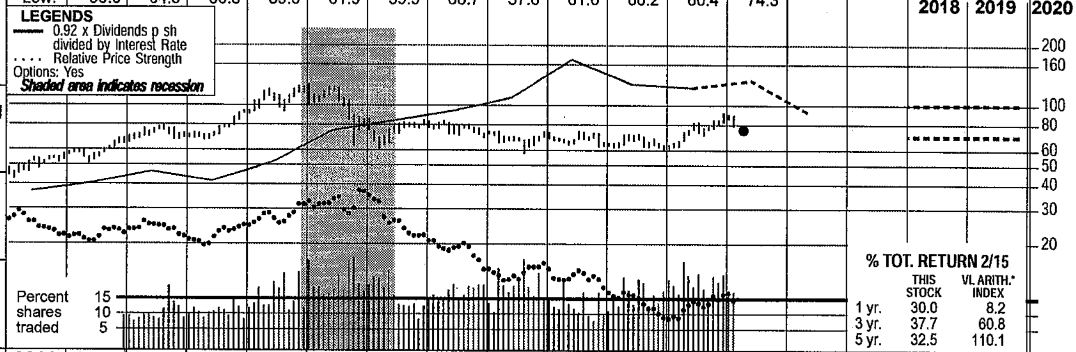
ENTERGY CORP. NYSE-ETR

RECENT PRICE	P/E RATIO	(Trailing: 13.1) (Median: 14.0)	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
75.48	14.8		0.80	4.4%	

TIMELINESS 4 Lowered 12/5/14
SAFETY 3 Lowered 3/22/13
TECHNICAL 2 Raised 3/20/15
BETA .70 (1.00 = Market)

High:	68.7	79.2	94.0	125.0	127.5	86.6	84.3	74.5	74.5	72.6	92.0	90.3
Low:	50.6	64.5	66.8	89.6	61.9	59.9	68.7	57.6	61.6	60.2	60.4	74.3

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+30%)	11%
Low	70	(-5%)	3%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	3	4	2	0	2	1	1	7	4
to Sell	3	4	2	0	2	1	1	9	4

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	237	241	251
to Sell	209	206	222
Hld's(000)	156315	158821	159093

% TOT. RETURN 2/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	30.0	8.2
3 yr.	37.7	60.8
5 yr.	32.5	110.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
35.51	45.61	43.59	37.34	40.17	46.69	46.61	53.94	59.47	69.15	56.82	64.27	63.67	57.94	63.86	69.70	68.50	69.90	Revenues per sh	76.50
5.06	6.49	6.41	7.62	7.43	8.33	8.18	10.69	11.73	12.89	13.29	16.54	17.53	15.98	16.25	17.70	17.90	17.95	"Cash Flow" per sh	20.75
2.25	2.97	3.08	3.68	3.69	3.93	4.40	5.36	5.60	6.20	6.30	6.66	7.55	6.02	4.96	5.77	5.50	5.05	Earnings per sh A	6.00
1.20	1.22	1.28	1.34	1.60	1.89	2.16	2.16	2.58	3.00	3.00	3.24	3.32	3.32	3.32	3.32	3.32	3.32	Div'd Decl'd per sh B ■ †	3.80
4.84	6.80	6.25	6.88	6.85	6.51	6.72	9.44	10.29	13.92	12.99	13.33	15.21	18.18	15.73	14.80	15.65	13.70	Cap'l Spending per sh	16.00
28.81	31.89	33.78	35.24	38.02	38.26	35.71	40.45	40.71	42.07	45.54	47.53	50.81	51.73	54.00	55.85	57.95	59.70	Book Value per sh C	65.75
247.08	219.60	220.73	222.42	228.90	216.83	216.83	202.67	193.12	189.36	189.12	178.75	176.36	177.81	178.37	179.25	179.50	179.50	Common Shs Outst'g D	179.50
13.2	10.1	12.5	11.5	13.8	15.1	16.3	14.3	19.3	16.6	12.0	11.6	9.1	11.2	13.2	12.9	Bold figures are	Value Line	Avg Ann'l P/E Ratio	14.0
.75	.66	.64	.63	.79	.80	.87	.77	1.02	1.00	.80	.74	.57	.71	.74	.68	estimates		Relative P/E Ratio	.90
4.1%	4.1%	3.3%	3.2%	3.1%	3.2%	3.0%	2.8%	2.4%	2.9%	4.0%	4.2%	4.9%	4.9%	5.1%	4.5%			Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $13643 mill. **Due in 5 Yrs** $4832.9 mill.
LT Debt $11635 mill. **LT Interest** $556.5 mill.
Incl. $814.2 mill. of securitization bonds.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $106.2 mill.
Pension Assets-12/13 $4429.2 mill.
Oblig. $5771.0 mill.
Pfd Stock $304.8 mill. **Pfd Div'd** $19.5 mill.
6,115,105 sh. 4.32%-8.25%, $100 par; 1,000,000 sh. 8.95%; 250,000 sh. 8.75%, all without sinking fund.
Common Stock 180,481,135 shs. as of 10/31/14
MARKET CAP: $14 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
10106	10932	11484	13094	10746	11488	11229	10302	11391	12495	12300	12550	Revenues ($mill)	13750
943.1	1160.9	1160.0	1240.5	1251.1	1270.3	1367.4	1091.9	904.5	1060.0	1015	930	Net Profit ($mill)	1095
37.2%	27.6%	30.7%	32.7%	33.6%	32.7%	17.3%	13.0%	26.7%	37.8%	23.0%	30.0%	Income Tax Rate	30.0%
8.0%	5.5%	5.8%	5.6%	7.4%	7.4%	8.9%	11.9%	10.1%	9.3%	10.0%	10.0%	AFUDC % to Net Profit	9.0%
51.9%	51.2%	54.3%	58.2%	55.3%	56.3%	52.2%	55.8%	55.1%	55.0%	55.5%	54.0%	Long-Term Debt Ratio	52.5%
45.5%	46.7%	43.9%	40.2%	43.1%	42.1%	46.4%	42.9%	43.6%	44.0%	43.5%	44.5%	Common Equity Ratio	46.5%
17013	17539	17902	19795	19985	20166	19324	21432	22109	22850	23975	24000	Total Capital ($mill)	25500
19197	19438	20974	22429	23389	23848	25609	27299	27882	28723	29375	29575	Net Plant ($mill)	30600
6.8%	8.0%	7.9%	7.5%	7.6%	7.7%	8.5%	6.4%	5.4%	6.0%	5.5%	5.05	Return on Total Cap'l	5.5%
11.5%	13.6%	14.2%	15.0%	14.0%	14.4%	14.8%	11.5%	9.1%	10.5%	9.5%	8.5%	Return on Shr. Equity	9.0%
11.9%	13.8%	14.4%	15.3%	14.3%	14.7%	15.0%	11.6%	9.2%	10.5%	9.5%	8.5%	Return on Com Equity E	9.0%
6.0%	8.3%	8.0%	8.1%	7.6%	7.6%	8.4%	5.2%	3.0%	4.5%	4.0%	3.0%	Retained to Com Eq	3.5%
51%	41%	46%	48%	48%	49%	45%	56%	68%	58%	61%	66%	All Div'ds to Net Prof	64%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+1.1	-1.5	+.7
Avg. Indust. Use (MWH)	991	975	910
Avg. Indust. Revs. per KWH(¢)	5.65	4.94	5.77
Capacity at Peak (Mw)	23979	23407	23802
Peak Load, Summer (Mw)	22387	21866	21581
Annual Load Factor (%)	60.0	60.0	62.0
% Change Customers (yr-end)	+.5	+.8	+.8
Fixed Charge Cov. (%)	339	254	245

BUSINESS: Entergy Corporation supplies electricity to 2.8 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 196,000 customers in Louisiana. Has a nonutility nuclear subsidiary that owns six units. Electric revenue breakdown: residential, 38%; commercial, 26%; industrial, 28%; other, 8%. Generating sources: nuclear, 33%; gas, 26%; coal, 12%; purchased, 29%. Fuel costs: 35% of revenues. '13 reported depreciation rate: 2.8%. Has 13,800 employees. Chairman & CEO: Leo Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	4.5%	.5%	3.0%
"Cash Flow"	9.0%	7.0%	3.0%
Earnings	6.0%	1.5%	-.5%
Dividends	9.0%	5.0%	2.0%
Book Value	4.0%	5.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	2384	2518	2964	2436	10302
2013	2609	2738	3352	2692	11391
2014	3208	2997	3458	2831	12494
2015	2850	2950	3550	2950	12300
2016	2900	3000	3650	3000	12550

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.40	2.06	1.89	1.67	6.02
2013	.90	.92	2.31	.83	4.96
2014	2.28	1.08	1.68	.74	5.77
2015	1.15	1.15	2.05	1.15	5.50
2016	1.05	1.05	1.90	1.05	5.05

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.83	.83	.83	.83	3.32
2012	.83	.83	.83	.83	3.32
2013	.83	.83	.83	.83	3.32
2014	.83	.83	.83	.83	3.32
2015	.83				

Entergy's earnings are likely to decline this year. Income from the company's nonregulated operations will probably be lower. In early 2014, this business benefited from a spike in power prices in New England. That did not occur this winter. Wholesale power prices have declined in recent months, too. And Entergy no longer has income ($0.20 a share last year) from the Vermont Yankee nuclear plant, which it closed at the end of 2014. Another factor is an increase in pension and nonpension benefits costs. Not everything is negative. The company's utilities are benefiting from volume growth, despite the decline in oil prices that has affected some of its industrial customers. The tax rate is likely to be much lower this year. Management's earnings guidance for 2015 is $5.10-$5.90 a share. Our estimate is at the midpoint of this range.

We look for earnings to fall again in 2016. We do not assume that Entergy will have as low a tax rate as in 2015. Operationally, we expect growth in utility income, based on continued kilowatt-hour sales growth and some rate relief, but a decline in profits from the nonregulated side of Entergy's business.

An asset purchase is pending. Three of Entergy's utility subsidiaries have agreed to pay $948 million for a 1,980-megawatt Union gas-fired generating station. The transaction requires the approval of the regulatory commissions in Arkansas, Louisiana, New Orleans, and Texas, plus that of the Federal Energy Regulatory Commission. It should be completed in late 2015. In Louisiana and Texas, the utility should be able to recover the cost of the Union plant through regulatory mechanisms.

Entergy will soon file a rate case in Arkansas. The application will seek to place the portion of the Union plant allocated to Arkansas in the rate base and improve its earned return on equity there.

The situation with the Indian Point nuclear station bears watching. Entergy wants to extend the two units' operating licenses by 20 years, but faces opposition from some officials in New York State.

Entergy stock is untimely, but offers a dividend yield and 3- to 5-year total return potential that are somewhat above the utility averages.

Paul E. Debbas, CFA *March 20, 2015*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '01, 15¢; '02, ($1.04); '03, 33¢ net; '05, (21¢); '12, ($1.26); '13, ($1.14); '14, (56¢). '14 EPS don't add due to rounding. Next earnings report due late April. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. deferred charges. In '13: $29.67/sh. (D) In mill. (E) Rate base: Net original cost. Allowed return on equity (blended): 10%; earned on avg. com. eq., '13: 9.3%. Regulatory Climate: Average.

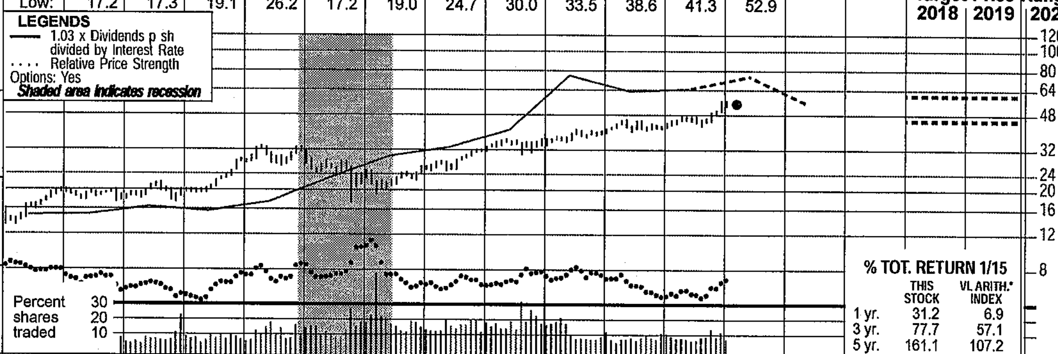
Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	80

NORTHEAST UTILITIES NYSE-NU

RECENT PRICE **54.68** | P/E RATIO **18.9** (Trailing: 21.3 Median: 18.0) | RELATIVE P/E RATIO **1.03** | DIV'D YLD **3.1%** | VALUE LINE

TIMELINESS **3** Lowered 12/19/14
SAFETY **2** Raised 5/25/12
TECHNICAL **4** Lowered 2/13/15
BETA .75 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	20.3	22.0	28.9	33.6	31.6	26.5	32.2	36.5	40.9	45.7	56.7	56.8
Low:	17.2	17.3	19.1	26.2	17.2	19.0	24.7	30.0	33.5	38.6	41.3	52.9



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+10%)	6%
Low	45	(-20%)	-1%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	1	0	1	0	0	1
to Sell	2	0	0	1	0	4	1	0	4

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	221	228	200
to Sell	192	187	213
Hld's(000)	209428	211525	215261

% TOT. RETURN 1/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	31.2	6.9
3 yr.	77.7	57.1
5 yr.	161.1	107.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
33.91	40.86	52.82	40.89	47.53	51.82	41.85	44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	*24.40*	*24.85*	*25.55*	Revenues per sh	*27.75*
5.68	3.39	10.48	6.32	5.80	5.00	5.46	3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	*4.80*	*5.20*	*5.60*	"Cash Flow" per sh	*6.75*
d1.14	d.20	1.37	1.08	1.24	.91	.98	.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	*2.85*	*3.05*	Earnings per sh A	*3.75*
.10	.40	.45	.53	.58	.63	.68	.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	*1.67*	*1.78*	Div'd Decl'd per sh B ■	*2.10*
2.50	2.88	3.40	3.86	4.31	4.85	5.89	5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	*5.35*	*5.80*	*6.65*	Cap'l Spending per sh	*6.25*
15.80	15.43	16.27	17.33	17.73	17.80	18.46	18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	*31.40*	*32.50*	*33.70*	Book Value per sh C	*38.00*
131.87	143.82	130.13	127.56	127.70	129.03	131.59	154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	*317.00*	*318.00*	*319.00*	Common Shs Outst'g D	*322.00*
--	--	14.1	16.1	13.4	20.8	19.8	27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
--	--	.72	.88	.76	1.10	1.05	1.46	.99	.82	.80	.85	.97	1.27	.95	.94	*Value Line*		Relative P/E Ratio	*.90*
.6%	1.9%	2.3%	3.0%	3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $9469.5 mill. Due in 5 Yrs $3552.1 mill.
LT Debt $8167.0 mill. LT Interest $361.8 mill.
(LT interest earned: 4.5x)

Leases, Uncapitalized Annual rentals $20.1 mill.
Pension Assets-12/13 $3985.9 mill. Oblig. $4676.5 mill.
Pfd Stock $155.6 mill. Pfd Div'd $7.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption.
Common Stock 316,799,371 shs. as of 10/31/14
MARKET CAP: $17 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
5507.3	6884.4	5822.2	5800.1	5439.4	4898.2	4465.7	6273.8	7301.2	7741.9	*7900*	*8150*	Revenues ($mill)	*8900*
128.5	126.2	251.5	296.2	335.6	377.8	400.3	533.0	793.7	827.1	*910*	*985*	Net Profit ($mill)	*1195*
30.8%	--	30.3%	29.7%	34.9%	36.6%	29.9%	34.0%	35.0%	36.2%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
17.4%	21.5%	13.9%	15.8%	4.6%	7.1%	8.6%	2.3%	1.4%	*4.0%*	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
63.2%	58.7%	59.2%	60.4%	57.2%	55.1%	53.4%	43.7%	44.3%	*44.5%*	*45.0%*	*45.5%*	Long-Term Debt Ratio	*45.5%*
35.1%	39.7%	39.2%	38.1%	41.5%	43.6%	45.3%	55.4%	54.8%	*54.5%*	*54.0%*	*54.0%*	Common Equity Ratio	*54.0%*
6923.2	7052.0	7431.1	7926.2	8629.5	8741.8	8856.0	16675	17544	*18275*	*19125*	*19925*	Total Capital ($mill)	*22700*
6417.2	6242.2	7229.9	8207.9	8840.0	9567.7	10403	16605	17576	*18725*	*19975*	*21425*	Net Plant ($mill)	*25600*
3.5%	2.9%	5.0%	5.4%	5.4%	5.8%	5.9%	4.2%	5.5%	*5.5%*	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
5.0%	4.3%	8.3%	9.4%	9.1%	9.6%	9.7%	5.7%	8.1%	*8.0%*	*8.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
5.1%	4.3%	8.4%	9.6%	9.2%	9.8%	9.8%	5.7%	8.2%	*8.0%*	*9.0%*	*9.0%*	Return on Com Equity E	*9.5%*
1.5%	.3%	4.3%	5.3%	4.7%	5.0%	5.0%	1.6%	3.4%	*3.0%*	*3.5%*	*4.0%*	Retained to Com Eq	*4.0%*
72%	94%	50%	45%	50%	49%	50%	72%	59%	*61%*	*59%*	*58%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-1.2	+47.0	+1.0
Avg. Indust. Use (MWH)	624	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.4	+59.8	NA
Fixed Charge Cov. (%)	291	320	427

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	-7.0%	-10.5%	*3.0%*
"Cash Flow"	-4.5%	-.5%	*5.5%*
Earnings	6.0%	9.0%	*8.0%*
Dividends	9.5%	11.0%	*7.0%*
Book Value	5.0%	8.0%	*4.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1100	1629	1861	1684	6273.8
2013	1995	1636	1893	1777	7301.2
2014	2291	1678	1892	1881	7741.9
2015	*2250*	*1750*	*2000*	*1900*	*7900*
2016	*2350*	*1800*	*2050*	*1950*	*8150*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.56	.15	.66	.55	1.89
2013	.72	.54	.66	.56	2.49
2014	.74	.40	.74	.69	2.58
2015	*.80*	*.60*	*.80*	*.65*	*2.85*
2016	*.85*	*.65*	*.85*	*.70*	*3.05*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.275	.275	.275	.275	1.10
2012	.294	.343	.343	.343	1.32
2013	.3675	.3675	.3675	.3675	1.47
2014	.3925	.3925	.3925	.3925	1.57
2015	.4175				

BUSINESS: Northeast Utilities is the parent of utilities that have 3.1 mill. elec., 492,000 gas customers. Connecticut Light & Power (CL&P) serves most of CT; Public Service Co. of New Hampshire (PSNH) supplies power to three fourths of NH's population; Western Massachusetts Electric Co. (WMECO) serves western MA; NSTAR supplies power to parts of eastern MA & gas to central & eastern MA. Yankee Gas serves CT. Acq'd NSTAR 4/12. Electric rev. breakdown: res'l, 49%; comm'l, 38%; ind'l, 5%; other, 8%. Fuel costs: 34% of revs. '13 reported depr. rates: 2.5%-3.0%. Has 8,700 employees. Chairman, President & CEO: Thomas J. May. Inc.: MA. Address: One Federal St., Building 111-4, Springfield, MA 01105. Tel.: 413-785-5871. Internet: www.eversource.com.

Northeast Utilities changed its name to Eversource Energy shortly after this report went to press. The company wanted to brand all of its utility subsidiaries under the Eversource name, and began doing business under the new name in early February. The stock was expected to begin trading under its new name and ticker symbol (ES) on February 19th.

Connecticut Light & Power received a rate increase. Tariffs were raised by $134.1 million (13.9%), based on a return of 9.17% on a common-equity ratio of 50.38%. The utility's allowed ROE for the first 12 months following the rate order is just 9.02% as a penalty for what the regulators deemed inadequate responses to storms in 2011. New tariffs took effect on December 1st. CL&P has not been earning an adequate ROE, so rate relief was sorely needed. The order includes a regulatory mechanism that decouples revenues and volume.

NSTAR Gas has a rate case pending in Massachusetts, and another gas filing is upcoming. The utility is seeking its first base rate hike in more than 20 years. It filed for an increase of $45.9 million (10.9%), based on a return of 10.25% on a common-equity ratio of 52.94%. New tariffs will take effect at the start of 2016. Yankee Gas in Connecticut will file a rate application in the second quarter.

We estimate solid earnings increases this year and next. Rate relief should help. Capital spending on electric transmission is another factor. NU's transmission budget for 2015 through 2018 is $3.9 billion. And the company continues to effect cost reductions stemming from its merger with NSTAR three years ago. Our 2015 earnings estimate is within NU's targeted range of $2.75-$2.90 a share.

The board of directors has increased the dividend. The board boosted the annual disbursement by $0.10 a share (6.4%). This is within the company's targeted growth rate of 6%-8% a year.

This stock's dividend yield is a cut below the mean for utilities. This reflects the company's superior dividend growth prospects. Like most utility issues, the recent price is within the 2018-2020 Target Price Range, so total return potential is low.

Paul E. Debbas, CFA *February 20, 2015*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, 10¢; '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢. '12 EPS don't add due to chng. in shs., '13 & '14 due to rounding. Next earnings report due early May. (B) Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. (C) Incl. def'd chgs. In '13: $23.09/sh. (D) In mill. (E) Rate allowed on com. eq. in MA: '11, 9.6%; in CT: (elec.) '15, 9.02% (gas) '11, 8.83%; in NH: '10, 9.67%; earn. on avg. com. eq., '13: 8.3%. Regul. Clim.: CT, Below Avg.; NH, Avg.; MA, Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	85

FIRSTENERGY NYSE-FE

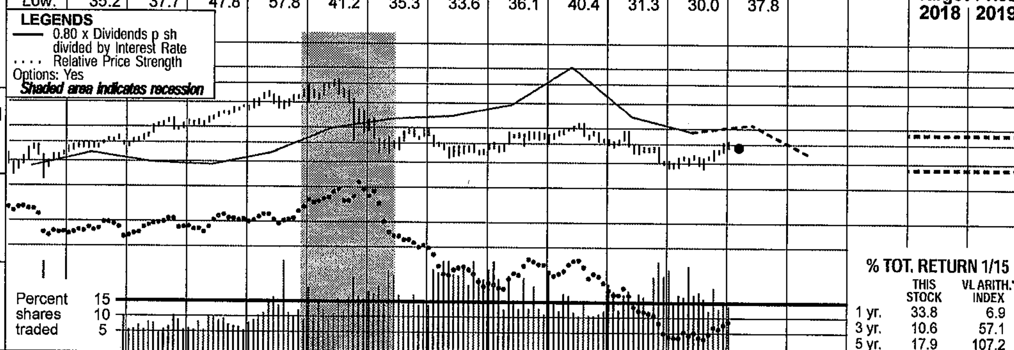
RECENT PRICE **38.62** | P/E RATIO **14.3** (Trailing: 15.4 Median: 15.0) | RELATIVE P/E RATIO **0.78** | DIV'D YLD **3.7%** | **VALUE LINE**

TIMELINESS **4** Lowered 12/12/14
SAFETY **3** Lowered 2/22/13
TECHNICAL **4** Lowered 2/6/15
BETA .70 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	43.4	53.4	61.7	75.0	84.0	53.6	47.8	46.5	51.1	46.8	40.8	41.7
Low:	35.2	37.7	47.8	57.8	41.2	35.3	33.6	36.1	40.4	31.3	30.0	37.8

Target Price Range 2018 | 2019 | 2020

LEGENDS
— 0.80 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+15%)	7%
Low	30	(-20%)	-2%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	0	0	0	0	0	0
to Sell	1	0	2	0	0	1	0	1	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	211	208	178
to Sell	238	210	219
Hld's(000)	303716	300665	311569

Percent shares traded 15 10 5

% TOT. RETURN 1/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	33.8	6.9
3 yr.	10.6	57.1
5 yr.	17.9	107.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
27.19	31.31	26.88	40.83	37.31	37.76	36.35	36.03	42.00	44.70	41.70	43.76	38.87	36.57	35.60	*36.10*	*36.60*	*37.55*	Revenues per sh	*40.25*
6.89	7.28	5.48	6.45	4.79	7.60	7.55	7.22	8.34	9.04	8.80	8.50	5.75	6.05	6.30	*5.55*	*6.25*	*6.40*	"Cash Flow" per sh	*7.00*
2.50	2.69	2.84	2.54	1.47	2.77	2.84	3.82	4.22	4.38	3.32	3.25	1.88	2.13	2.97	*2.10*	*2.75*	*2.80*	Earnings per sh A	*3.00*
1.50	1.50	1.50	1.50	1.50	1.91	1.71	1.85	2.05	2.20	2.20	2.20	2.20	2.20	1.65	1.44	*1.44*	*1.48*	Div'd Decl'd per sh B ■	*1.60*
2.69	2.74	2.86	3.35	2.60	2.57	3.66	4.12	5.36	9.47	7.23	6.44	5.45	7.09	6.90	*8.60*	*6.95*	*6.80*	Cap'l Spending per sh	*7.50*
19.63	20.72	24.86	23.92	25.13	26.04	27.86	28.30	29.45	27.17	28.08	28.03	31.75	31.29	30.32	*31.05*	*32.35*	*33.70*	Book Value per sh C	*37.75*
232.45	224.53	297.64	297.64	329.84	329.84	329.84	319.21	304.84	304.84	304.84	304.84	418.22	418.22	418.63	*421.00*	*423.50*	*426.00*	Common Shs Outst'g D	*433.50*
11.3	9.2	10.9	13.0	22.5	14.1	16.1	14.2	15.6	15.6	13.0	11.7	22.4	21.1	13.1	*16.1*	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.64	.60	.56	.71	1.28	.74	.86	.77	.83	.94	.87	.74	1.41	1.34	.74	*.85*	*Value Line*		Relative P/E Ratio	*.80*
5.3%	6.1%	4.8%	4.6%	4.5%	4.9%	3.7%	3.4%	3.1%	3.2%	5.1%	5.8%	5.2%	4.9%	4.3%	4.3%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $21538 mill. **Due in 5 Yrs** $8875 mill.
LT Debt $18531 mill. **LT Interest** $965 mill.
Incl. $154 mill. capitalized leases.
(LT interest earned: 2.4x)

Leases, Uncapitalized Annual rentals $202 mill.
Pension Assets-12/13 $6171 mill. **Oblig.** $8263 mill.

Pfd Stock None

Common Stock 420,792,515 shs.
as of 10/31/14
MARKET CAP: $16 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
11989	11501	12802	13627	12712	13339	16258	15294	14903	*15200*	*15500*	*16000*	Revenues ($mill)	*17500*
951.0	1265.0	1309.0	1342.0	1015.0	991.0	752.0	891.0	1245.0	*895*	*1165*	*1190*	Net Profit ($mill)	*1340*
42.1%	38.6%	40.3%	36.7%	19.6%	38.6%	41.3%	41.1%	36.1%	*30.5%*	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
2.0%	2.1%	2.4%	3.9%	12.8%	16.6%	9.3%	8.1%	6.0%	*12.0%*	*6.0%*	*6.0%*	AFUDC % to Net Profit	*6.0%*
46.5%	48.6%	49.7%	52.4%	58.2%	59.5%	54.2%	53.7%	55.5%	*56.0%*	*55.5%*	*55.5%*	Long-Term Debt Ratio	*55.0%*
52.4%	51.4%	50.3%	47.7%	41.8%	40.5%	45.8%	46.3%	44.5%	*44.0%*	*44.5%*	*44.5%*	Common Equity Ratio	*45.0%*
17527	17570	17846	17383	20467	21124	28996	28263	28523	*29600*	*30850*	*32125*	Total Capital ($mill)	*36400*
13998	14667	15383	17723	19164	19788	30337	32903	33252	*35500*	*37025*	*38450*	Net Plant ($mill)	*43000*
7.1%	9.0%	9.0%	9.7%	6.9%	6.3%	4.0%	4.9%	6.0%	*4.5%*	*5.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
10.1%	14.0%	14.6%	16.2%	11.9%	11.6%	5.7%	6.8%	9.8%	*7.0%*	*8.5%*	*8.5%*	Return on Shr. Equity	*8.0%*
10.2%	13.9%	14.6%	16.2%	11.9%	11.6%	5.7%	6.8%	9.8%	*7.0%*	*8.5%*	*8.5%*	Return on Com Equity E	*8.0%*
4.2%	7.4%	7.7%	8.1%	4.0%	3.8%	NMF	NMF	2.6%	*2.0%*	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
59%	47%	47%	50%	66%	68%	117%	103%	74%	*68%*	*52%*	*53%*	All Div'ds to Net Prof	*52%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.1	+3.5	+.9
Avg. Indust. Use (MWH)	NMF	NMF	NMF
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	206	236	294

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	.5%	-2.0%	*1.0%*
"Cash Flow"	1.0%	-6.0%	*2.0%*
Earnings	--	-11.0%	*3.5%*
Dividends	3.0%	--	*-3.5%*
Book Value	2.5%	2.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3986	3757	4051	3500	15294
2013	3724	3512	4020	3647	14903
2014	4189	3496	3888	*3627*	*15200*
2015	*4050*	*3750*	*4000*	*3700*	*15500*
2016	*4200*	*3850*	*4150*	*3800*	*16000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.78	.52	1.05	d.23	2.13
2013	.51	.47	.88	1.11	2.97
2014	.34	.27	.79	*.70*	*2.10*
2015	*.65*	*.50*	*.85*	*.75*	*2.75*
2016	*.65*	*.50*	*.90*	*.75*	*2.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.55	.55	.55	.55	2.20
2012	.55	.55	.55	.55	2.20
2013	.55	.55	.55	.55	2.20
2014	.36	.36	.36	.36	1.44
2015	.36				

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, Jersey Central Power & Light, West Penn Power, Potomac Edison, & Mon Power. Provides electric service to over 6 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown by customer class not available. Generating sources: coal, 44%; nuclear, 26%; purchased, 30%. Fuel costs: 43% of revenues. '13 reported deprec. rate: 2.6%. Has 15,800 employees. Chairman: Anthony J. Alexander. President & CEO: Charles E. Jones. Inc.: Ohio. Address: 76 South Main Street, Akron, Ohio 44308-1890. Tel.: 800-736-3402. Internet: www.firstenergycorp.com.

FirstEnergy has made progress in some of its regulatory matters. The Federal Energy Regulatory Commission granted the company's request for forward-looking tariff regulation, effective at the start of 2015. (The utility's allowed return on equity in this business is now 12.38%, but this might be lowered.) The West Virginia commission approved a settlement calling for a total rate increase of $63 million for FirstEnergy's two utilities in the state, effective February 25th. The company's four utilities in Pennsylvania reached a settlement calling for rate hikes totaling $293 million. A ruling is expected by May 19th. This settlement, and the order in West Virginia, were "black box" agreements in which an allowed ROE was not specified.

Other regulatory matters are pending. FirstEnergy is asking the Ohio commission to approve a three-year extension of its Electric Security Plan. This would include 15-year agreements through which the company's utilities in the state would purchase the output of some generating assets, including the Davis-Besse nuclear unit and the Sammis coal-fired plant. Jersey Central Power & Light filed for a tariff hike of $9.1 million, based on an 11% ROE. However, an administrative law judge recommended a cut of $107.5 million. Each of these matters will probably be resolved within the next several weeks.

A dividend increase is possible next year—if not sooner. FirstEnergy is waiting for its regulatory matters to be resolved so that it can gauge the earning power of its utility operations. We estimate a dividend hike in 2016. However, we think the disbursement won't approach its previous $2.20-a-share level, even over the 3- to 5-year period.

Earnings should return to a more normal level this year, followed by a modest increase in 2016. Last year, some unusual (but not nonrecurring) charges reduced profits. FirstEnergy's earnings growth will probably be driven by its regulated utility operations.

The dividend yield of this untimely stock is a bit above the utility average. With the recent price above the midpoint of our 2018-2020 Target Price Range, total return potential is unimpressive.

Paul E. Debbas, CFA *February 20, 2015*

(A) Dil. EPS. Excl. nonrec. gain (losses): '05, (28¢); '09, (3¢); '10, (68¢); '11, 33¢; '12, (29¢); '13, ($2.07); '14, (17¢); gains from disc. ops.: '05, 5¢; '13, 4¢; '14, 20¢. '12 EPS don't add due to rounding. Next earnings report due early May. (B) Div'ds paid early Mar., June, Sep. & Dec. 5 div'ds decl. in '04, 3 in '13. ■ Div'd reinv. avail. (C) Incl. intang.: In '13: $19.76/sh. (D) In mill. (E) Rate base: Depr. orig. cost. Rates all'd on com. eq.: 9.75%-12.9%; earned on avg. com. eq., '13: 9.3%. Reg. Climate: OH Above Avg.; PA, NJ Avg.; MD, WV Below Avg.

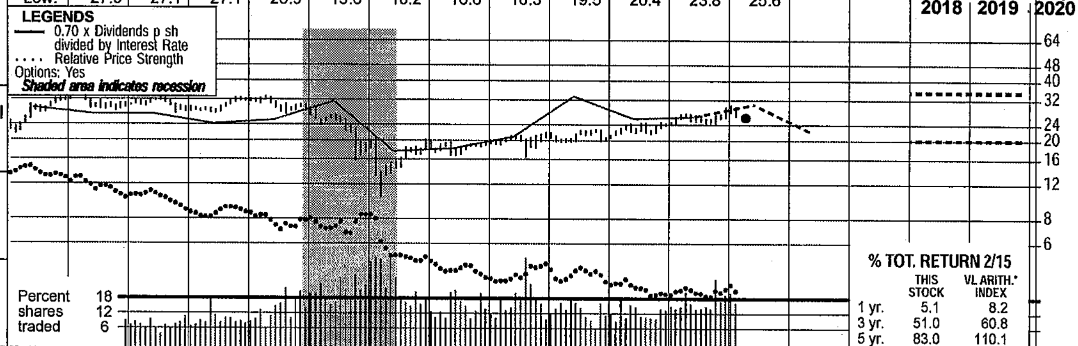
Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	65

GREAT PLAINS EN'GY NYSE-GXP

RECENT PRICE 26.09 | P/E RATIO 17.7 (Trailing: 16.7 Median: 15.0) | RELATIVE P/E RATIO 0.96 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Lowered 9/19/14
SAFETY 3 Lowered 12/26/08
TECHNICAL 3 Raised 3/20/15
BETA .85 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	35.7	32.8	32.8	33.4	29.3	20.5	19.9	22.1	22.8	24.9	29.5	30.3
Low:	27.9	27.1	27.1	26.9	15.6	10.2	16.6	16.3	19.5	20.4	23.8	25.6



% TOT. RETURN 2/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.1	8.2
3 yr.	51.0	60.8
5 yr.	83.0	110.1

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+35%)	11%
Low	20	(-25%)	-1%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	125	124	132
to Sell	117	122	125
Hld's(000)	118540	117299	119797

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
14.50	18.02	23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	15.05	15.90	*16.65*	*17.50*	*18.40*	Revenues per sh	*19.50*
3.63	4.63	4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	3.45	4.01	*4.01*	*4.10*	*4.65*	"Cash Flow" per sh	*5.50*
1.26	2.05	1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	1.35	1.62	1.57	*1.45*	*1.75*	Earnings per sh A	*2.00*
1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	.86	.88	.94	*1.00*	*1.06*	Div'd Decl'd per sh B ■	*1.20*
2.97	6.67	4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	4.01	4.42	*5.10*	*5.25*	*3.90*	Cap'l Spending per sh	*3.75*
13.97	14.88	12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	21.75	22.58	*23.25*	*23.70*	*24.40*	Book Value per sh C	*26.75*
61.91	61.91	61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	153.53	153.87	*154.20*	*154.50*	*154.75*	Common Shs Outst'g D	*155.50*
20.0	12.4	15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	15.5	14.2	16.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.5*
1.14	.81	.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.01	.99	.80	.87			Relative P/E Ratio	*.85*
6.6%	6.5%	6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%	4.1%	3.8%	3.6%			Avg Ann'l Div'd Yield	*4.6%*
						2604.9	2675.3	3267.1	1670.1	1965.0	2255.5	2318.0	2309.9	2446.3	2568.2	*2700*	*2850*	Revenues ($mill)	*3200*
						164.2	127.6	159.2	119.5	135.6	211.7	174.4	199.9	250.2	242.8	*230*	*270*	Net Profit ($mill)	*315*
						18.7%	27.0%	30.7%	34.5%	25.0%	31.7%	32.7%	34.3%	34.0%	32.3%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
						2.1%	8.4%	10.6%	46.8%	57.0%	25.7%	3.9%	3.3%	10.4%	*12.0%*	*8.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
						47.5%	30.6%	40.7%	49.7%	53.2%	50.2%	47.8%	44.9%	50.0%	*49.0%*	*48.5%*	*45.0%*	Long-Term Debt Ratio	*45.5%*
						50.9%	67.5%	57.9%	49.6%	46.2%	49.2%	51.6%	54.4%	49.4%	*50.5%*	*51.0%*	*54.5%*	Common Equity Ratio	*54.0%*
						2403.3	1988.4	2709.8	5146.2	6044.5	5867.6	5741.2	6135.8	7029.1	*7115*	*7190*	*6920*	Total Capital ($mill)	*7725*
						2765.6	3066.2	3444.5	6081.3	6651.1	6892.3	7053.5	7402.1	7746.4	8279.6	*8680*	*8835*	Net Plant ($mill)	*9000*
						8.2%	7.9%	7.5%	3.5%	3.9%	5.3%	5.0%	5.0%	5.0%	*4.5%*	*4.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
						13.0%	9.2%	9.9%	4.6%	4.8%	7.2%	5.8%	5.9%	7.1%	*6.5%*	*6.0%*	*7.0%*	Return on Shr. Equity	*7.5%*
						13.3%	9.4%	10.1%	4.6%	4.8%	7.3%	5.8%	5.9%	7.2%	*6.5%*	*6.0%*	*7.0%*	Return on Com Equity E	*7.5%*
						3.2%	NMF	.9%	NMF	.9%	3.4%	2.0%	2.2%	3.2%	*2.5%*	*2.0%*	*3.0%*	Retained to Com Eq	*3.0%*
						76%	104%	91%	NMF	81%	54%	66%	63%	55%	*60%*	*68%*	*61%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $3899.2 mill. **Due in 5 Yrs** $1339.1 mill.
LT Debt $3488.1 mill. **LT Interest** $180.3 mill.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $15.3 mill.
Pension Assets-12/13 $703.0 mill.
Oblig. $1007.4 mill.
Pfd Stock $39.0 mill. **Pfd Div'd** $1.6 mill.
390,000 shs. 3.80% to 4.50% (all $100 par & cum.), callable from $101 to $103.70.
Common Stock 154,124,361 shs.
as of 11/3/14
MARKET CAP: $4.0 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-1.7	-1.8	+.2
Avg. Indust. Use (MWH)	1463	1443	1424
Avg. Indust. Revs. per KWH (¢)	6.11	6.23	6.80
Capacity at Peak (Mw)	6697	6719	NA
Peak Load, Summer (Mw)	5690	5653	NA
Annual Load Factor (%)	50.5	49.6	NA
% Change Customers (avg.)	- -	+.2	+.7
Fixed Charge Cov. (%)	211	235	267

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	-5.0%	-11.0%	*3.5%*
"Cash Flow"	-2.5%	-.5%	*6.5%*
Earnings	-3.5%	-2.0%	*5.0%*
Dividends	-6.5%	-12.5%	*5.5%*
Book Value	5.0%	3.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	479.7	603.6	746.2	480.4	2309.9
2013	542.2	600.3	765.0	538.8	2446.3
2014	585.1	648.4	782.5	552.2	2568.2
2015	*600*	*650*	*850*	*600*	*2700*
2016	*625*	*700*	*900*	*625*	*2850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	d.07	.41	.95	.03	1.35
2013	.17	.41	.93	.11	1.62
2014	.15	.34	.95	.12	1.57
2015	*.15*	*.30*	*.90*	*.10*	*1.45*
2016	*.20*	*.40*	*1.00*	*.15*	*1.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.2075	.2075	.2075	.2125	.84
2012	.2125	.2125	.2125	.2175	.86
2013	.2175	.2175	.2175	.23	.88
2014	.23	.23	.23	.245	.94
2015	.245				

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 831,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acq'd Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 42%; commercial, 40%; industrial, 9%; other, 9%. Generating sources: coal, 75%; nuclear, 11%; wind, 1%; gas & oil, 1%; purchased, 12%. Fuel costs: 27% of revs. '13 reported deprec. rate (utility): 3.0%. Has 3,000 employees. Chairman: Michael J. Chesser. President & CEO: Terry Bassham. Inc.: Missouri. Address: 1200 Main St., Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.

Great Plains Energy's largest utility subsidiary has rate cases pending in Missouri and Kansas. In Missouri, Kansas City Power & Light is seeking an increase of $120.9 million (15.8%), based on a 10.3% return on a 50.36% common-equity ratio. In Kansas, the utility is requesting a hike of $67.3 million (12.5%), based on a 10.3% return on a 50.48% common-equity ratio. The filings are driven by a need to place environmental spending at the La Cygne coal-fired plant and upgrades to the Wolf Creek nuclear unit in the rate base. KCP&L also wants to recover higher transmission costs and property taxes. In Missouri, the utility is asking for a fuel-adjustment clause that would include transmission expenses, along with a regulatory mechanism to track property taxes. New tariffs should go into effect around the start of the fourth quarter. Because that is a seasonally weak period for the company, any rate relief KCP&L obtains won't have a large effect on profits this year. In fact . . .

Earnings will probably decline this year. Unrecovered property taxes and transmission costs will result in a significant amount of regulatory lag for the company in 2015—even more than we had expected in our December report. Thus, we have cut our share-earnings estimate by $0.15, to $1.45. Our revised estimate is within the company's targeted (and wide) range of $1.35-$1.60. Despite our expectation of lower profits, the payout ratio is still low enough to allow for a dividend increase this year. Note that Great Plains Energy benefits from tax-loss carryforwards that aren't reflected in our "cash flow" figures.

Regulatory lag is nothing new for Great Plains Energy. This problem has persisted for the past several years. That's why returns on equity have been mediocre since 2008.

We forecast significant bottom-line improvement in 2016. We assume reasonable regulatory treatment in our estimate of $1.75 a share, which would result in an increase of more than 20%.

The dividend yield and 3- to 5-year total return potential for Great Plains Energy stock are about average, compared with most utility issues.

Paul E. Debbas, CFA *March 20, 2015*

(A) Dil. EPS. Excl. nonrec. gains (losses): '00, 49¢; '01, ($2.01); '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; gain (losses) on disc. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢. '12 EPS don't add due to change in shs., '14 due to rounding. Next earnings report due early May. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '13: $6.62/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in MO in '13: 9.7%; in KS in '13: 9.5%; earned on avg. com. eq., '13: 7.3%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	5
Earnings Predictability	70

IDACORP, INC. NYSE-IDA

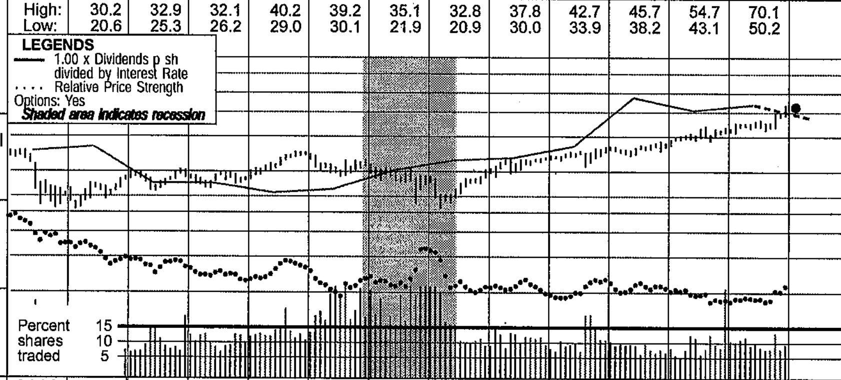
RECENT PRICE 68.20 | P/E RATIO 18.6 (Trailing: 18.3 Median: 14.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Lowered 12/12/14
SAFETY 2 Raised 8/2/13
TECHNICAL 3 Raised 1/2/15
BETA .80 (1.00 = Market)

High:	30.2	32.9	32.1	40.2	39.2	35.1	32.8	37.8	42.7	45.7	54.7	70.1	
Low:	20.6	25.3	26.2	29.0	30.1	21.9	20.9	30.0	33.9	38.2	43.1	50.2	

Target Price Range 2017 | 2018 | 2019

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(5%)	3%
Low	50	(-25%)	-4%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	1	0	0	0	0
Options	2	0	0	0	0	0	0	0	0
to Sell	2	3	0	2	2	0	4	1	1

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	92	86	70
to Sell	84	106	106
Hld's(000)	37877	36553	36655

Percent shares traded 15 10 5

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	31.8	6.9
3 yr.	71.7	73.7
5 yr.	143.3	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
29.83	17.50	27.10	150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	24.50	25.10	Revenues per sh	27.10
4.69	4.50	5.63	5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.23	5.74	5.84	6.21	6.25	6.40	"Cash Flow" per sh	6.90
2.37	2.43	3.50	3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.75	3.60	Earnings per sh A	3.75
1.86	1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.90	Div'd Decl'd per sh B†■	2.20
2.37	2.95	3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.70	6.45	Cap'l Spending per sh	12.95
19.42	20.02	21.82	23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.60	40.30	Book Value per sh C	44.90
37.61	37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.20	50.20	Common Shs Outst'g D	50.20
14.4	12.7	10.9	11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	15.1		Avg Ann'l P/E Ratio	16.0
.75	.72	.71	.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.72	.79	.75	.79		Relative P/E Ratio	1.00
5.4%	6.0%	4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%		Avg Ann'l Div'd Yield	3.6%

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
844.5	859.5	926.3	879.4	960.4	1049.8	1036.0	1026.8	1080.7	1246.2	1250	1260	Revenues ($mill)	1360
77.8	63.7	100.1	82.3	98.4	124.4	142.5	166.9	168.9	182.4	180	180	Net Profit ($mill)	190
--	16.9%	13.3%	14.3%	16.3%	15.2%	--	--	13.4%	28.3%	24.0%	25.0%	Income Tax Rate	30.0%
3.9%	4.7%	4.0%	9.7%	10.2%	10.5%	19.7%	22.8%	7.1%	4.2%	7.5%	8.0%	AFUDC % to Net Profit	9.5%
49.3%	50.0%	45.2%	48.9%	47.6%	50.2%	49.3%	45.6%	45.5%	46.6%	48.0%	48.0%	Long-Term Debt Ratio	48.5%
50.7%	50.0%	54.8%	51.1%	52.4%	49.8%	50.7%	54.4%	54.5%	53.4%	52.0%	52.0%	Common Equity Ratio	51.5%
1987.8	2048.8	2052.8	2364.2	2485.9	2807.1	3020.4	3045.2	3225.4	3465.9	3715	3890	Total Capital ($mill)	4415
2209.5	2314.3	2419.1	2616.6	2758.2	2917.0	3161.4	3406.6	3536.0	3665.0	3900	4095	Net Plant ($mill)	4740
5.3%	4.5%	6.2%	4.7%	5.3%	5.7%	6.0%	6.7%	6.5%	6.4%	6.0%	5.5%	Return on Total Cap'l	5.0%
7.7%	6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.0%	9.0%	Return on Shr. Equity	8.5%
7.2%	6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	9.6%	9.9%	9.0%	9.0%	Return on Com Equity E	8.5%
2.7%	1.3%	4.3%	2.4%	3.4%	4.8%	5.5%	6.5%	5.7%	5.6%	4.5%	4.0%	Retained to Com Eq	3.5%
65%	80%	51%	64%	55%	46%	41%	36%	41%	43%	51%	53%	All Div'ds to Net Prof	58%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1615.4 mill. Due in 5 Yrs $124.3 mill.
LT Debt $1614.3 mill. LT Interest $81.5 mill.
(LT interest earned: 6.3x)

Pension Assets-12/13 $545.1 mill.
Oblig. $695.1 mill.

Pfd Stock None

Common Stock 50,268,748 shs.
as of 10/24/14

MARKET CAP: $3.4 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+1.6	+2.6	+3.8
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	4.54	4.63	5.21
Capacity at Peak (Mw)	N/A	N/A	N/A
Peak Load, Summer (Mw)	2973	3245	3407
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.7	+1.1	+1.5
Fixed Charge Cov. (%)	194	283	329

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-10.0%	2.0%	3.5%
"Cash Flow"	3.0%	6.5%	2.5%
Earnings	5.5%	10.0%	1.5%
Dividends	-2.5%	3.0%	8.0%
Book Value	4.5%	5.5%	4.0%

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	251.5	235.0	309.6	230.7	1026.8
2012	241.1	254.7	334.0	250.9	1080.7
2013	264.9	303.9	381.1	296.3	1246.2
2014	292.7	317.7	382.2	257.4	1250
2015	290	305	385	280	1260

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.60	.42	2.16	.18	3.36
2012	.50	.71	1.84	.33	3.37
2013	.70	.93	1.46	.55	3.64
2014	.55	.89	1.73	.58	3.75
2015	.60	.75	1.85	.40	3.60

Cal-endar	QUARTERLY DIVIDENDS PAID B†■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.30	.30	.30	.30	1.20
2012	.33	.33	.33	.38	1.37
2013	.38	.38	.38	.43	1.57
2014	.43	.43	.43	.47	1.76
2015					

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a utility that operates 17 hydroelectric generation developments, 3 natural gas-fired plants, and partly owns three coal plants across Idaho, Oregon, Wyoming, and Nevada. Service territory covers 24,000 square miles, serving 501,000 business customers. Sells electricity in Idaho (95% of revenues) and Oregon (5%). Revenue breakdown: residential, 40%; commercial, 22%; industrial, 14%; other, 24%. Fuel sources: hydro, 45%; thermal, 34%; purchased power, 21%. '13 depr rate: 2.4%. Has 2,067 employees. Chairman: Robert A. Tinstman. President & CEO: Darrel T. Anderson. Incorp: Idaho. Address: 1221 W. Idaho St., Boise, ID 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

We are raising our 2014 share-net estimate for IDACORP. Third-quarter results were above our expectations. Better than expected results were due to slightly improved weather in the September period. Customer growth has also aided sales volume, as it has helped to offset lower usage among the company's residential and irrigation customer categories. However, earnings in the September period were primarily impacted by lower income tax expense. This was due to a tax method change related to Idaho Power's capitalized repairs reduction. IDACORP recently raised its guidance for 2014 to reflect the lower tax expense. The company expects 2014 earnings to be in the range of $3.70 to $3.80 per share, higher than the previous guidance of $3.50 to $3.65 per share. In accordance, we have raised our 2014 estimate to $3.75 per share. Looking ahead, the method change is expected to result in a small amount of continued benefit, depending on the nature of annual capital additions at Idaho Power. IDACORP expects more clarity on this in the next quarter.

Idaho Power is currently working on its 2015 Integrated Resource Plan. The plan is expected to indicate a modest increase in the average and peak load growth from the company's earlier IRP in 2013. The completed Integrated Resource Plan is expected to be filed with the Idaho Public Utility Commission by June 2015.

A dividend hike is likely in 2015. The company's dividend policy seeks to maintain a payout ratio between 50% and 60%. The board of directors recently increased the dividend payout in September, 2014 by 9.3%. The dividend should continue to see an improvement until IDACORP reaches the upper end of the payout range.

These shares do not stand out at this juncture. Based on the stock's current Timeliness rank, it is expected to be an average performer over the next six to 12 months. However, appreciation potential over the next 3- to 5-year period is limited, as the stock price is already at the top of our three- to five-year Target Price Range. Additionally, although further dividend increases are likely, the company's current dividend yield is presently below the average yield of 3.3% for electric utilities.

Saumya Ajila *January 30, 2015*

(A) EPS diluted. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Egs. may not sum to total due to rounding. Next earnings report due in late February. (B) Div'ds historically paid in late Feb., May, Aug., and late Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '13: $21.06/sh. (D) In mill. (E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '11: 9.5%-10.5%; earned on avg. system com. eq., '13: 9.6%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	80
Earnings Predictability	90

MGE ENERGY INC. NDQ-MGEE

RECENT PRICE **41.52** | P/E RATIO **17.4** (Trailing: 17.9 / Median: 16.0) | RELATIVE P/E RATIO **0.95** | DIV'D YLD **2.8%** | VALUE LINE

TIMELINESS **3** Raised 3/6/15
SAFETY **1** New 1/3/03
TECHNICAL **3** Raised 3/20/15
BETA .70 (1.00 = Market)

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+30%)	10%
Low	45	(+10%)	5%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

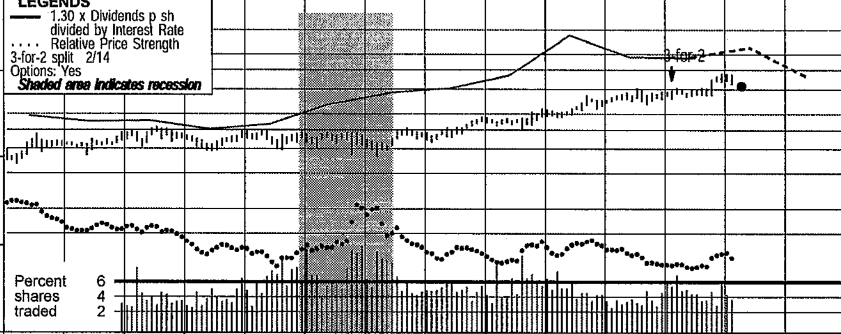
Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	55	43	42
to Sell	53	62	54
Hld's(000)	11517	11389	11590

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	24.3	25.8	24.7	24.8	24.3	25.5	29.1	31.9	37.4	40.5	48.0
Low:	18.4	20.3	19.5	19.6	18.6	18.2	21.4	24.7	28.7	33.4	35.7

Note: the printed High/Low rows have 12 values: 24.3 25.8 24.7 24.8 24.3 25.5 29.1 31.9 37.4 40.5 48.0 48.0 (High) and 18.4 20.3 19.5 19.6 18.6 18.2 21.4 24.7 28.7 33.4 35.7 40.7 (Low).

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 2/14
Options: Yes
Shaded area indicates recession



% TOT. RETURN 2/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.8	8.2
3 yr.	60.9	60.8
5 yr.	129.0	110.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
11.30	13.00	13.03	13.17	14.59	13.89	16.73	16.13	16.33	17.35	15.40	15.36	15.76	15.61	17.04	17.88	**18.55**	**19.45**	Revenues per sh	**22.20**
2.54	2.59	2.52	2.22	1.96	1.92	2.00	2.34	2.46	2.68	2.66	2.76	2.94	2.98	3.28	3.49	**3.70**	**4.00**	"Cash Flow" per sh	**5.15**
.99	1.11	1.08	1.13	1.14	1.18	1.05	1.37	1.51	1.59	1.47	1.67	1.76	1.86	2.16	2.32	**2.40**	**2.55**	Earnings per sh A	**3.30**
.87	.88	.89	.89	.90	.91	.92	.93	.94	.96	.97	.99	1.01	1.04	1.07	1.11	**1.15**	**1.19**	Div'd Decl'd per sh B ■	**1.35**
2.11	2.96	1.65	2.97	3.02	3.13	2.80	2.94	4.14	3.08	2.35	1.76	1.88	2.84	3.43	2.67	**2.85**	**3.15**	Cap'l Spending per sh	**4.45**
7.66	8.04	8.45	8.62	9.56	11.06	11.21	11.93	12.99	13.92	14.47	15.14	15.89	16.71	17.81	19.02	**20.00**	**21.15**	Book Value per sh E	**25.00**
24.24	24.93	25.61	26.36	27.52	30.59	30.68	31.46	32.93	34.36	34.67	34.67	34.67	34.67	34.67	34.67	**35.00**	**35.00**	Common Shs Outst'g C	**36.00**
14.0	11.7	14.8	16.0	17.5	18.0	22.4	15.9	15.0	14.2	15.1	15.0	15.8	17.2	17.0	17.2	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**15.0**
.80	.76	.76	.87	1.00	.95	1.19	.86	.80	.85	1.01	.95	.99	1.09	.96	.90	*estimates*		Relative P/E Ratio	**.95**
6.3%	6.7%	5.5%	5.0%	4.5%	4.3%	3.9%	4.3%	4.1%	4.2%	4.4%	4.0%	3.6%	3.2%	2.9%	2.8%			Avg Ann'l Div'd Yield	**2.7%**

CAPITAL STRUCTURE as of 12/31/14
Total Debt $406.5 mill. Due in 5 Yrs $78.8 mill.
LT Debt $395.3 mill. LT Interest $19.0 mill.
(LT interest earned: 7.5x)

Leases, Uncapitalized Annual rentals $1.6 mill.
Pension Assets-12/14 $288.5 mill.
Obligation $340.2 mill.
Pfd Stock None

Common Stock 34,668,370 shs.
as of 2/1/15
MARKET CAP: $1.4 billion (Mid Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
513.4	507.5	537.6	596.0	533.8	532.6	546.4	541.3	590.9	619.9	**650**	**680**	Revenues ($mill)	**800**
32.1	42.4	48.8	52.8	51.0	57.7	60.9	64.4	74.9	80.3	**85.0**	**90.0**	Net Profit ($mill)	**120**
38.2%	37.9%	36.3%	35.5%	35.6%	36.9%	37.1%	37.7%	37.5%	37.5%	**35.0%**	**35.0%**	Income Tax Rate	**35.0%**
--	--	--	--	--	--	--	--	2.2%	2.0%	**2.0%**	**2.0%**	AFUDC % to Net Profit	**2.0%**
39.3%	38.7%	35.2%	36.3%	39.0%	38.9%	39.6%	38.2%	39.3%	37.5%	**37.5%**	**37.5%**	Long-Term Debt Ratio	**35.0%**
60.7%	61.3%	64.8%	63.7%	61.0%	61.1%	60.4%	61.8%	60.7%	62.5%	**62.5%**	**62.5%**	Common Equity Ratio	**65.0%**
566.2	612.6	660.1	750.6	822.7	859.4	911.9	937.9	1016.9	1054.7	**1120**	**1180**	Total Capital ($mill)	**1385**
667.7	728.4	844.0	901.2	939.8	968.0	995.6	1073.5	1160.2	1208.1	**1260**	**1310**	Net Plant ($mill)	**1650**
6.6%	7.8%	8.1%	7.7%	6.9%	7.6%	7.8%	7.9%	8.3%	8.5%	**8.5%**	**8.5%**	Return on Total Cap'l	**9.5%**
9.3%	11.3%	11.4%	11.0%	10.2%	11.0%	11.1%	11.1%	12.1%	12.2%	**12.0%**	**12.0%**	Return on Shr. Equity	**13.5%**
9.3%	11.3%	11.4%	11.0%	10.2%	11.0%	11.1%	11.1%	12.1%	12.2%	**12.0%**	**12.0%**	Return on Com Equity D	**13.5%**
1.2%	3.7%	4.3%	4.4%	3.4%	4.4%	4.7%	4.9%	6.1%	6.4%	**6.5%**	**6.5%**	Retained to Com Eq	**8.0%**
87%	67%	62%	60%	66%	60%	57%	56%	50%	48%	**47%**	**46%**	All Div'ds to Net Prof	**41%**

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-0.3	-0.8	-0.5
Avg. Indust. Use (MWH)	2472	2502	2463
Avg. Indust. Revs. per KWH (¢)	7.86	7.94	7.78
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	766	783	783
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	579	676	702

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	2.0%	.5%	4.5%
"Cash Flow"	5.0%	4.5%	8.0%
Earnings	6.5%	7.0%	7.5%
Dividends	2.0%	2.5%	4.0%
Book Value	6.0%	5.5%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	149.3	117.2	137.8	137.0	541.3
2013	167.2	128.3	140.1	155.3	590.9
2014	210.3	128.8	135.1	145.7	619.9
2015	*215*	*135*	*145*	*155*	*650*
2016	*220*	*142*	*153*	*165*	*680*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.46	.41	.68	.31	1.86
2013	.65	.40	.70	.41	2.16
2014	.80	.41	.67	.44	2.32
2015	*.80*	*.45*	*.70*	*.45*	*2.40*
2016	*.84*	*.48*	*.74*	*.49*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.2501	.2501	.2551	.2551	1.01
2012	.2551	.2551	.2634	.2634	1.04
2013	.2634	.2634	.2717	.2717	1.07
2014	.2717	.2717	.2825	.2825	1.11
2015	.2825				

BUSINESS: MGE Energy Inc. is a holding company for Madison Gas and Electric, which provides electric service to approximately 143,000 customers in a 316-square-mile area of Dane County and gas service to 149,000 customers in 1,678 square miles in seven counties in Wisconsin. Electric revenue breakdown, '14: residential, 33%; commercial, 53%; industrial, 5%; public authorities and other, 9%. Generating sources, '14: coal, 48%; purchased power, 46%; natural gas and other, 6%. Fuel costs: 19% of revenues. '14 reported depreciation rate: 3.4%. Has 699 employees. Chairman, President & CEO: Gary J. Wolter. Incorporated: Wisconsin. Address: 133 South Blair St., Madison, WI 53788. Telephone: 608-252-7000. Internet: www.mgeenergy.com.

Shares of MGE Energy have traded somewhat lower over the past three months. The company reported mixed results for the fourth quarter of 2014. Revenue of $145.7 million declined moderately, on a year-over-year basis. But efforts to control operating expenses and lower benefits costs boosted profitability, and share earnings of $0.44 improved nicely over the prior-year tally.

A rate case has recently been resolved. In late December, the Public Service Commission of Wisconsin authorized MGE to increase 2015 rates for retail electric customers by $15.4 million (3.8%) and decrease gas rates by $3.8 million (2.0%). The increase in retail electric rates covers expenses associated with the construction of emission-reduction equipment, improvements to the state's electric transmission system, along with fuel and purchased power costs. The authorized return on equity is 10.2%.

We envision further improvement in the current year. The company's utility operations should continue to benefit from favorable demographics. A healthy local economy will likely drive population growth and demand for power in the Madison, Wisconsin area. The aforementioned rate relief should also boost revenues. Efforts to keep expenses in check ought to further benefit the bottom line. Solid growth will probably continue at Otter Tail in 2016.

The risk profile is attractive here. The company has established a track record of stable operating performance, and we expect this to continue. Low exposure to economically sensitive industrial customers increases the stability of earnings. Moreover, leverage appears manageable. As a result, MGE earns very good marks for Safety, Financial Strength, Price Stability, and Earnings Predictability.

Conservative investors with a long-time horizon might find these shares attractive. Looking out to 2018-2020, the stock offers decent total return potential, on a risk-adjusted basis. This should be supported by moderate growth in revenues, earnings, and dividends at the company over the pull to late decade. This equity is neutrally ranked for year-ahead relative price performance.

Michael Napoli, CFA *March 20, 2015*

(A) Diluted earnings. Next earnings report due early May. (B) Dividends historically paid in mid-March, June, September, and December. ■ Dvd. reinvestment plan available. (C) In millions, adjusted for split. (D) Rate allowed on common equity in '14: 10.2%; earned on common equity, '14: 12.2%. Regulatory Climate: Above Average. (E) Includes regulatory assets. In 2014: $156.8 mill., $4.52 per share.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	95

NORTHWESTERN NYSE-NWE

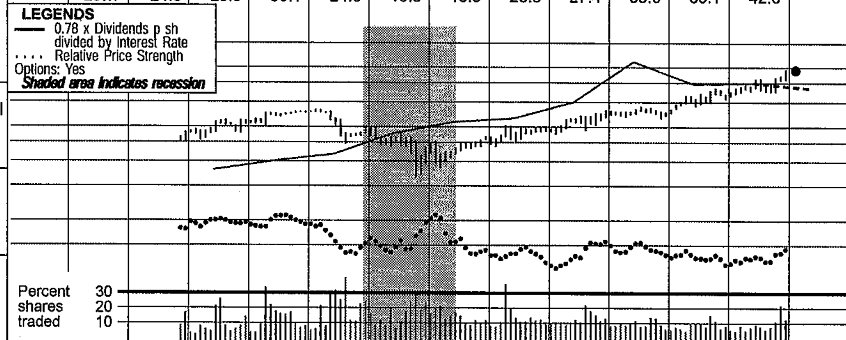
RECENT PRICE **58.02** | P/E RATIO **18.0** (Trailing: 20.6 / Median: NMF) | RELATIVE P/E RATIO **0.98** | DIV'D YLD **3.3%** | VALUE LINE

High:	28.2	32.5	35.8	36.7	29.7	26.8	30.6	36.6	38.0	47.2	58.7
Low:	24.8	25.5	30.1	24.5	16.5	18.5	23.8	27.4	33.0	35.1	42.6

Target Price Range 2017 | 2018 | 2019

TIMELINESS 2 Raised 9/19/14
SAFETY 3 New 5/4/12
TECHNICAL 3 Raised 12/5/14
BETA .70 (1.00 = Market)

LEGENDS
— 0.78 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+5%)	4%
Low	40	(-30%)	-4%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	87	88	79
to Sell	92	84	93
Hld's(000)	37582	38301	38766

Percent shares traded 30 / 20 / 10

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	35.0	6.9
3 yr.	76.8	73.7
5 yr.	167.4	107.3

NorthWestern Corporation filed for protection under Chapter 11 of the Federal Bankruptcy Code on September 14, 2003. On November 1, 2004, the company emerged from a bankruptcy reorganization. All old common shares were canceled and 35,500,000 new shares (along with 4,620,333 warrants) were issued. The stock initially traded on NASDAQ under the symbol NWEC and moved to the NYSE under the symbol NWE in May of 2008.

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
29.18	32.57	31.49	30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.55	29.25	Revenues per sh	32.25
3.20	4.00	3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.20	6.45	"Cash Flow" per sh	7.25
d14.32	1.71	1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.95	3.20	Earnings per sh A	3.50
--	1.00	1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	Div'd Decl'd per sh B ■ †	2.15
2.25	2.26	2.81	3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.80	6.50	Cap'l Spending per sh	5.50
19.92	20.60	20.65	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.75	33.00	Book Value per sh C	37.00
35.60	35.79	35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	47.00	47.00	Common Shs Outst'g D	47.00
--	17.1	26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.5		Avg Ann'l P/E Ratio	14.5
--	.91	1.40	1.15	.84	.77	.82	.79	1.00	.95	.85		Relative P/E Ratio	.90
--	3.4%	3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%		Avg Ann'l Div'd Yield	4.3%
1039.0	1165.8	1132.7	1200.1	1260.8	1141.9	1110.7	1117.3	1070.3	1154.5	1200	1375	Revenues ($mill)	1515
41.1	61.5	49.2	53.2	67.6	73.4	77.4	92.6	83.7	94.0	115	150	Net Profit ($mill)	170
--	38.5%	40.3%	37.8%	37.3%	17.2%	25.0%	9.8%	9.6%	13.2%	NMF	17.0%	Income Tax Rate	20.0%
2.9%	2.1%	3.3%	2.5%	2.3%	7.2%	22.7%	5.4%	15.2%	14.1%	13.0%	10.0%	AFUDC % to Net Profit	6.0%
51.8%	44.3%	49.9%	50.1%	46.8%	56.4%	57.2%	52.2%	53.8%	53.5%	53.0%	50.0%	Long-Term Debt Ratio	45.5%
48.2%	55.7%	50.1%	49.9%	53.2%	43.6%	42.8%	47.8%	46.2%	46.5%	47.0%	50.0%	Common Equity Ratio	54.5%
1472.9	1324.0	1482.2	1648.4	1434.3	1803.9	1916.4	1797.1	2020.7	2215.7	3185	3095	Total Capital ($mill)	3175
1379.1	1409.2	1491.9	1770.9	1839.7	1964.1	2118.0	2213.3	2435.6	2690.1	3705	3855	Net Plant ($mill)	4225
5.7%	7.0%	5.2%	5.0%	7.0%	6.0%	6.0%	7.1%	5.5%	5.5%	5.0%	6.0%	Return on Total Cap'l	6.5%
5.8%	8.3%	6.6%	6.5%	8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.0%	9.5%	Return on Shr. Equity	9.5%
5.8%	8.3%	6.6%	6.5%	8.9%	9.3%	9.4%	10.8%	9.0%	9.1%	8.0%	9.5%	Return on Com Equity E	9.5%
5.8%	3.5%	.7%	.7%	2.3%	3.2%	3.5%	4.7%	3.2%	3.5%	3.0%	4.0%	Retained to Com Eq	4.0%
--	58%	90%	89%	74%	66%	63%	56%	65%	61%	59%	60%	All Div'ds to Net Prof	60%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1382.3 mill. **Due in 5 Yrs** $384.2 mill.
LT Debt $1210.7 mill. **LT Interest** $64.2 mill.
Incl. $28.6 mill. capitalized leases.
(LT interest earned: 2.4x)

Leases, Uncapitalized Annual rentals $1.7 mill.
Pension Assets-12/13 $516.4 mill. **Oblig.** $567.9 mill.

Pfd Stock None

Common Stock 39,143,732 shs.
as of 10/17/14
MARKET CAP: $2.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+2.3	+.3	+1.3
Avg. Indust. Use (MWH)	39347	38865	39486
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2014	2108	2056
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.8	+.7
Fixed Charge Cov. (%)	237	210	217

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	--	-1.5%	1.5%
"Cash Flow"	--	6.5%	5.0%
Earnings	--	10.0%	6.5%
Dividends	--	3.0%	6.5%
Book Value	--	3.5%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	338.3	251.8	244.0	283.2	1117.3
2012	309.1	244.6	235.8	280.8	1070.3
2013	313.0	260.2	262.2	319.1	1154.5
2014	369.7	270.3	251.9	308.1	1200
2015	400	310	305	360	1375

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.89	.30	.41	.93	2.53
2012	.88	.31	.30	.78	2.26
2013	1.01	.37	.40	.68	2.46
2014	1.17	.20	.77	.81	2.95
2015	1.20	.45	.55	1.00	3.20

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.36	.36	.36	.36	1.44
2012	.37	.37	.37	.37	1.48
2013	.38	.38	.38	.38	1.52
2014	.40	.40	.40	.40	1.60
2015					

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 407,000 electric customers in Montana and South Dakota and 272,000 gas customers in Montana (83% of gross margin), South Dakota (15%), and Nebraska (2%). Electric revenue breakdown: residential, 41%; commercial, 50%; industrial, 5%; other, 4%. Generating sources are not provided by company. Fuel costs: 42% of revenues. '13 reported depreciation rate: 3.2%. Has 1,600 employees. Chairman: Dr. E. Linn Draper Jr. President & CEO: Robert C. Rowe. Incorporated: Delaware. Address: 3010 West 69th Street, Sioux Falls, South Dakota 57108. Telephone: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern has completed the purchase of some hydro assets. The company paid $903 million for 633 megawatts of hydro capacity. NorthWestern wants to increase the proportion of its power that comes from its own generating assets (instead of being purchased). The transaction was completed in mid-November. A rate increase of $117 million took effect at that time in order to place the newly purchased assets in the rate base. NorthWestern issued $400 million of common stock and $450 million of long-term debt to finance the deal.

Thanks to the purchase, earnings will likely rise significantly in 2015. This should occur even though the company booked $0.43 a share of tax benefits in the third quarter of 2014. NorthWestern's preliminary 2015 earnings guidance is $3.07-$3.32 a share.

Shareholders can expect a sizable dividend increase soon. NorthWestern is targeting a 60% payout ratio. We estimate that the board of directors will raise the quarterly payout by $0.08 a share (20%).

The company is seeking an electric rate hike in South Dakota. NorthWestern filed for an increase of $26.5 million (20.2%), based on a 10% return on a 53.6% common-equity ratio. The requested rate boost is large, but the utility hasn't had a base rate hike in 35 years. New tariffs are expected to take effect in mid-2015.

NorthWestern is involved in a dispute with the Federal Energy Regulatory Commission (FERC). The company believes that 80% of the costs associated with one of its gas-fired plants should be allocated to its customers in Montana, with the remainder allocated to its FERC-regulated wholesale customers. FERC says only 4% should be allocated to wholesale users, and ordered NorthWestern to make a refund to customers. The company already took a $0.12-a-share charge in the June quarter of 2012. FERC has agreed to a rehearing, but when this matter will be resolved is not known.

This timely stock's dividend yield (reflecting the estimated increase) is average for a utility. With the recent price near the upper end of our 2017-2019 Target Price Range, total return potential is nonexistent.

Paul E. Debbas, CFA *January 30, 2015*

(A) Diluted EPS. Excl. gain (loss) on disc. ops.: '05, (6¢); '06, 1¢; nonrec. gain: '12, 39¢ net. '12 EPS don't add due to rounding. Next earnings report due mid-Feb. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. def'd charges. In '13: $17.34/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '14 (elec.): 9.8%; in '13 (gas): 9.8%; in SD in '11: none specified; in NE in '07: 10.4%; earned on avg. com. eq., '13: 9.6%. Regul. Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	95

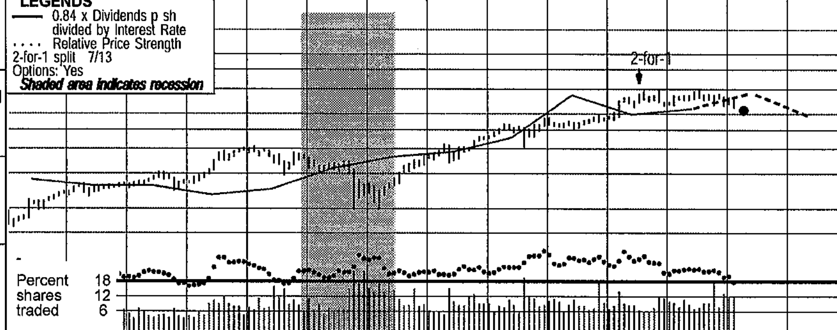
OGE ENERGY CORP. NYSE-OGE

RECENT PRICE 31.38 | P/E RATIO 16.2 (Trailing: 15.8 / Median: 14.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Raised 5/9/14
SAFETY 1 Raised 9/19/14
TECHNICAL 3 Raised 2/27/15
BETA .90 (1.00 = Market)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	13.5	15.3	20.3	20.7	18.1	18.9	23.1	28.6	30.1	40.0	39.3	36.5
Low:	11.4	12.2	13.2	14.6	9.8	9.9	16.9	20.3	25.1	27.7	32.8	31.4

LEGENDS
— 0.84 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/13
Options: Yes
Shaded area indicates recession



Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+25%)	10%
Low	35	(+10%)	7%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	2	0	0	2	0	0	3	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	134	147	171
to Sell	141	125	134
Hld's(000)	116179	117222	122042

Percent shares traded 18 12 6

% TOT. RETURN 2/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.3	8.2
3 yr.	33.4	60.8
5 yr.	104.3	110.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
13.95	21.17	20.40	19.26	21.62	27.37	32.83	21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	12.75	13.45	Revenues per sh	15.00
2.03	2.07	1.81	1.87	1.82	1.87	1.94	2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.40	3.60	"Cash Flow" per sh	4.00
.97	.95	.65	.72	.87	.89	.92	1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.85	2.00	Earnings per sh A	2.25
.67	.67	.67	.67	.67	.67	.67	.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	Div'd Decl'd per sh B ■	1.55
1.16	1.15	1.44	1.49	1.04	1.51	1.65	2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.85	2.75	2.80	Cap'l Spending per sh	2.50
6.55	6.83	6.67	6.27	6.87	7.14	7.59	8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.25	17.10	17.95	Book Value per sh C	20.25
155.73	155.84	155.98	157.00	174.80	180.00	181.20	182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.50	200.00	200.50	Common Shs Outst'g D	202.00
12.1	10.6	17.4	14.1	11.8	14.1	14.9	13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	Bold figures are		Avg Ann'l P/E Ratio	17.0
.69	.69	.89	.77	.67	.74	.79	.74	.73	.75	.72	.85	.90	.97	.99	.97	Value Line		Relative P/E Ratio	1.05
5.7%	6.6%	5.9%	6.6%	6.5%	5.3%	4.9%	4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	estimates		Avg Ann'l Div'd Yield	4.1%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $2921.1 mill. **Due in 5 Yrs** $1247.0 mill.
LT Debt $2509.7 mill. **LT Interest** $145.3 mill.
(LT interest earned: 4.8x)

Leases, Uncapitalized Annual rentals $6.7 mill.

Pension Assets-12/13 $654.9 mill. **Oblig.** $658.1 mill.

Pfd Stock None

Common Stock 199,319,096 shs.

MARKET CAP: $6.3 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
5948.2	4005.6	3797.6	4070.7	2869.7	3716.9	3915.9	3671.2	2867.7	2453.1	2550	2700	Revenues ($mill)	3050
166.1	226.1	244.2	231.4	258.3	295.3	342.9	355.0	387.6	395.8	375	400	Net Profit ($mill)	460
30.2%	34.8%	32.3%	30.4%	31.7%	34.9%	30.7%	26.0%	24.9%	30.4%	30.0%	30.0%	Income Tax Rate	30.0%
1.3%	3.8%	1.6%	1.7%	9.1%	5.7%	9.0%	2.7%	2.6%	1.7%	4.0%	3.0%	AFUDC % to Net Profit	2.0%
49.5%	45.6%	44.4%	53.3%	50.6%	50.8%	51.6%	50.7%	43.1%	46.0%	44.5%	45.0%	Long-Term Debt Ratio	48.5%
50.5%	54.4%	55.6%	46.7%	49.4%	49.2%	48.4%	49.3%	56.9%	54.0%	55.5%	55.0%	Common Equity Ratio	51.5%
2726.6	2950.1	3025.5	4058.6	4129.7	4652.5	5300.4	5615.8	5337.2	6000	6175	6555	Total Capital ($mill)	7975
3567.4	3867.5	4246.3	5249.8	5911.6	6464.4	7474.0	8344.8	6672.8	6979.9	7220	7465	Net Plant ($mill)	8300
7.6%	9.1%	9.5%	7.0%	7.9%	7.8%	7.8%	7.7%	8.6%	8.0%	7.5%	7.5%	Return on Total Cap'l	7.0%
12.1%	14.1%	14.5%	12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.0%	11.0%	11.0%	Return on Shr. Equity	11.0%
12.1%	14.1%	14.5%	12.2%	12.7%	12.9%	13.4%	12.8%	12.8%	12.0%	11.0%	11.0%	Return on Com Equity E	11.0%
3.4%	6.6%	7.1%	5.4%	6.0%	6.7%	7.7%	7.2%	7.3%	6.5%	5.0%	4.5%	Retained to Com Eq	3.5%
72%	53%	51%	55%	53%	48%	43%	44%	43%	47%	56%	58%	All Div'ds to Net Prof	68%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+3.4	-1.8	+1.1
Avg. Indust. Use (MWH)	752	776	779
Avg. Indust. Revs. per KWH (¢)	5.37	5.07	5.44
Capacity at Peak (Mw)	7115	7139	NA
Peak Load, Summer (Mw)	7057	7000	6341
Annual Load Factor (%)	52.2	51.6	NA
% Change Customers (yr-end)	+.8	+1.1	+1.1
Fixed Charge Cov. (%)	427	404	367

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	-1.5%	-4.0%	NMF
"Cash Flow"	6.5%	8.5%	2.0%
Earnings	9.5%	7.5%	3.0%
Dividends	2.0%	3.0%	10.0%
Book Value	8.0%	8.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	840.7	855.0	1113.4	862.1	3671.2
2013	901.4	734.2	723.2	508.9	2867.7
2014	560.4	611.8	754.7	526.2	2453.1
2015	575	625	800	550	2550
2016	600	675	850	575	2700

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.19	.48	.94	.20	1.79
2013	.12	.46	1.08	.29	1.94
2014	.25	.50	.94	.29	1.98
2015	.20	.50	.95	.20	1.85
2016	.20	.55	1.05	.20	2.00

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.1875	.1875	.1875	.1875	.75
2012	.19675	.19675	.19675	.19675	.79
2013	.20875	.20875	.20875	.20875	.84
2014	.225	.225	.225	.25	.93
2015	.25				

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 815,000 customers in Oklahoma (88% of electric revenues) and western Arkansas (9%); wholesale is (3%). Owns 26.3% of Enable Midstream Partners. Acquired Transok 6/99. Electric revenue breakdown: residential, 42%; commercial, 26%; industrial, 19%; other, 13%. Generating sources: coal, 42%; gas, 32%; wind, 5%; purchased, 21%. Fuel costs: 50% of revenues. '13 reported depreciation rate (utility): 2.8%. Has 2,400 employees. Chairman & CEO: Peter B. Delaney. President: Sean Trauschke. Inc.: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. Tel.: 405-553-3000. Internet: www.oge.com.

OGE Energy's earnings are likely to decline this year. One reason is a probable falloff in equity income from the company's 26.3% stake in Enable Midstream Partners, an oil and gas master limited partnership. Enable has seen a decline in the rig count in its operating area, and although most of its business is fee-based, the drop in commodity prices is another negative factor. Another reason is regulatory lag at Oklahoma Gas and Electric, due to higher depreciation, unrecovered transmission costs, and the ending of a wholesale power contract. We have slashed our earnings estimate by $0.25 a share, to $1.85. Our revised estimate is within OGE's guidance of $1.76-$1.89.

The utility is awaiting a ruling from the Oklahoma Corporation Commission (OCC) on its environmental compliance plan. OG&E plans to spend $1.1 billion through 2019 to comply with EPA mandates. The utility would recover these costs through riders on customers' bills. After the OCC has issued its decision, OG&E will file a general rate case (probably in the June quarter) to address the aforementioned reasons for regulatory lag. New tariffs would take effect six months later, meaning that any rate relief the company gets this year will come too late to help lift profits much in 2015. OG&E is also planning a rate case in Arkansas, possibly by the end of the current quarter.

We look for earnings to recover next year. We assume reasonable regulatory treatment, and that the contribution from Enable will be greater than in 2015 (but not back to the 2014 level).

OGE still intends to increase the dividend at an annual rate of 10% through 2019. We note that the percentage decline in expected distributions from Enable isn't nearly as large as that of expected equity income. In addition, OGE's low payout ratio and solid finances give the board of directors the wherewithal to increase the disbursement rapidly.

This high-quality stock is suitable for investors seeking dividend growth. The quotation has fallen 12% so far in 2015, which has been a weak year for most utility issues. Even after the pullback, though, the dividend yield is a cut below the utility average.

Paul E. Debbas, CFA *March 20, 2015*

(A) Diluted EPS. Excl. nonrecurring losses: '02, 20¢; '03, 7¢; '04, 3¢; gains on discontinued operations: '02, 6¢; '05, 25¢; '06, 20¢. '13 EPS don't add due to rounding. Next earnings report due early May. (B) Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan available. (C) Incl. deferred charges. In '13: $1.91/sh. (D) In millions, adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in Oklahoma in '12: 10.2%; in Arkansas in '11: 9.95%; earned on avg. com. eq., '13: 13.2%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	90
Price Growth Persistence	90
Earnings Predictability	95

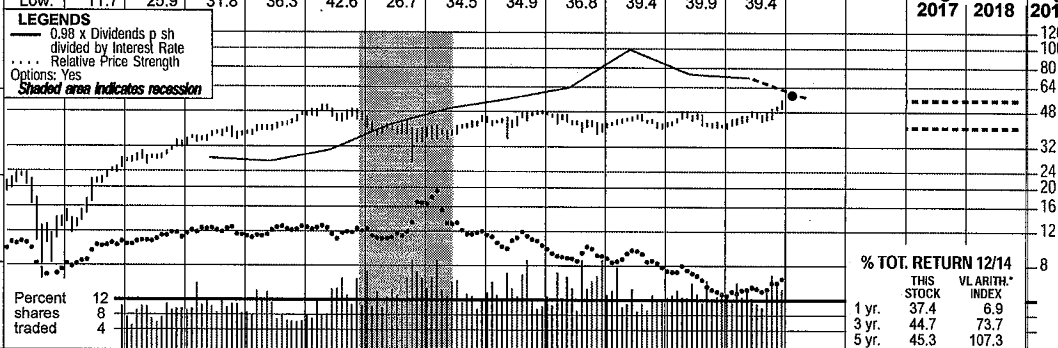
PG&E CORP. NYSE-PCG

RECENT PRICE 58.30 | P/E RATIO 16.9 (Trailing: 19.7 Median: 15.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 3 Lowered 12/19/14
SAFETY 3 Lowered 2/3/12
TECHNICAL 3 Raised 11/28/14
BETA .65 (1.00 = Market)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	28.0	34.5	40.1	48.2	52.2	45.7	45.8	48.6	48.0	47.0	48.5	55.2
Low:	11.7	25.9	31.8	36.3	42.6	26.7	34.5	34.9	36.8	39.4	39.9	39.4

Target Price Range 2017 | 2018 | 2019



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(-5%)	2%
Low	40	(-30%)	-4%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	0	0
to Sell	0	6	0	1	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	217	206	210
to Sell	203	205	186
Hld's(000)	370504	387652	390623

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	37.4	6.9
3 yr.	44.7	73.7
5 yr.	45.3	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
52.12	57.74	67.75	63.18	32.74	25.05	26.47	31.78	36.02	37.42	40.51	36.15	35.02	36.28	34.92	34.16	*35.50*	*35.90*	Revenues per sh	*41.00*
6.08	7.15	.80	5.66	1.14	4.80	5.71	7.12	7.76	8.02	8.44	8.37	8.22	8.08	7.32	6.33	*7.95*	*7.95*	"Cash Flow" per sh	*9.25*
1.88	2.24	d9.21	3.02	d2.36	2.05	2.12	2.35	2.76	2.78	3.22	3.03	2.82	2.78	2.07	1.83	*3.15*	*2.95*	Earnings per sh A	*3.50*
1.20	1.20	1.20	--	--	--	--	1.23	1.32	1.44	1.56	1.68	1.82	1.82	1.82	1.82	1.82	*1.82*	Div'd Decl'd per sh B ■ †	*2.10*
4.23	4.39	4.54	7.33	7.94	4.08	3.72	4.90	6.90	7.83	10.05	10.68	9.62	9.79	10.74	11.40	*10.70*	*11.35*	Cap'l Spending per sh	*11.25*
21.08	19.10	8.19	11.89	9.47	10.12	20.62	19.60	22.44	24.18	25.97	27.88	28.55	29.35	30.35	31.41	*33.25*	*34.60*	Book Value per sh C	*39.25*
382.60	360.59	387.19	363.38	381.67	416.52	418.62	368.27	348.14	353.72	361.06	370.60	395.23	412.26	430.72	456.67	*476.00*	*485.00*	Common Shs Outst'g D	*500.00*
16.8	13.1	--	4.8	--	9.5	13.8	15.4	14.8	16.8	12.1	13.0	15.8	15.5	20.7	23.7	*14.6*		Avg Ann'l P/E Ratio	*13.5*
.87	.75	--	.25	--	.54	.73	.82	.80	.89	.73	.87	1.01	.97	1.32	1.33	*.75*		Relative P/E Ratio	*.85*
3.8%	4.1%	4.8%	--	--	--	--	3.4%	3.2%	3.1%	4.0%	4.3%	4.1%	4.2%	4.2%	4.2%	4.0%		Avg Ann'l Div'd Yield	*4.4%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $14981 mill. **Due in 5 yrs** $2849 mill.
LT Debt $14555 mill. **LT Interest** $720 mill.
Incl. $90 mill. capitalized leases.
(LT interest earned: 3.4x)
Pension Assets-12/13 $12527 mill. **Oblig.** $14077 mill.
Pfd Stock $252 mill. **Pfd Div'd** $14 mill.
4,534,958 shs. 4.36% to 5%, cumulative and $25 par, redeemable from $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cumulative nonredeemable and $25 par.
Common Stock 475,088,027 shs. **as of 10/20/14**
MARKET CAP: $28 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
11080	11703	12539	13237	14628	13399	13841	14956	15040	15598	*16900*	*17400*	Revenues ($mill)	*20500*
901.0	904.0	1005.0	1020.0	1198.0	1168.0	1113.0	1132.0	893.0	828.0	*1495*	*1445*	Net Profit ($mill)	*1830*
35.0%	37.6%	35.5%	34.6%	26.2%	31.1%	33.0%	30.3%	23.9%	24.5%	*20.0%*	*25.0%*	Income Tax Rate	*26.5%*
3.6%	5.6%	6.7%	9.4%	9.5%	11.9%	14.4%	11.2%	17.5%	17.9%	*9.0%*	*10.0%*	AFUDC % to Net Profit	*8.0%*
45.1%	48.3%	51.7%	52.6%	52.2%	51.4%	49.6%	48.8%	48.7%	46.6%	*48.0%*	*47.5%*	Long-Term Debt Ratio	*49.5%*
53.2%	50.0%	46.8%	46.1%	46.5%	47.4%	49.3%	50.2%	50.4%	52.5%	*51.5%*	*52.0%*	Common Equity Ratio	*50.0%*
16242	14446	16696	18558	20163	21793	22863	24119	25956	27311	*30850*	*32375*	Total Capital ($mill)	*39200*
18989	19955	21785	23656	26261	28892	31449	33655	37523	41252	*44050*	*47125*	Net Plant ($mill)	*56000*
7.6%	8.1%	7.6%	7.4%	7.8%	6.7%	6.2%	5.9%	4.7%	4.2%	*6.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
10.1%	12.1%	12.5%	11.6%	12.4%	11.0%	9.6%	9.2%	6.7%	5.7%	*9.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
10.3%	12.3%	12.7%	11.8%	12.6%	11.2%	9.7%	9.2%	6.7%	5.7%	*9.5%*	*8.5%*	Return on Com Equity E	*9.5%*
10.3%	7.7%	6.8%	6.0%	6.8%	5.5%	3.9%	3.4%	1.0%	.2%	*4.0%*	*3.5%*	Retained to Com Eq	*4.0%*
1%	39%	47%	50%	47%	52%	61%	63%	85%	96%	*58%*	*61%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-.3	+6.0	+.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	9.51	9.17	9.28
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.4	+.5	+.3
Fixed Charge Cov. (%)	295	231	223

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-1.5%	-1.5%	*2.5%*
"Cash Flow"	6.5%	-2.0%	*4.0%*
Earnings	9.5%	-5.5%	*8.0%*
Dividends	--	5.0%	*2.5%*
Book Value	11.0%	4.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	3597	3684	3860	3815	14956
2012	3641	3593	3976	3830	15040
2013	3672	3776	4175	3975	15598
2014	3891	3952	4939	*4118*	*16900*
2015	*4150*	*4150*	*4850*	*4250*	*17400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.50	.91	.68	.69	2.78
2012	.66	.55	.87	d.01	2.07
2013	.55	.74	.36	.19	1.83
2014	.49	.57	1.71	*.38*	*3.15*
2015	*.65*	*.70*	*1.05*	*.55*	*2.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.455	.455	.455	.455	1.82
2012	.455	.455	.455	.455	1.82
2013	.455	.455	.455	.455	1.82
2014	.455	.455	.455	.455	1.82
2015	.455				

BUSINESS: PG&E Corporation is a holding company for Pacific Gas and Electric Company and nonutility subsidiaries. Supplies electricity and gas to most of northern and central California. Has 5.3 million electric and 4.4 million gas customers. Electric revenue breakdown: residential, 41%; commercial, 39%; industrial, 11%; agricultural, 8%; other, 1%. Generating sources: nuclear, 24%; hydro, 11%; gas, 8%; purchased, 57%. Fuel costs: 38% of revenues. '13 reported depreciation rate (utility): 3.5%. Has 21,200 employees. Chairman, President & Chief Executive Officer: Anthony F. Earley, Jr. Incorporated: California. Address: One Market, Spear Tower, Suite 2400, San Francisco, California 94105. Telephone: 415-267-7000. Internet: www.pgecorp.com.

Will 2015 be the year in which the uncertainties surrounding the explosion of a PG&E gas pipeline in San Bruno, California are finally resolved? In September of 2010, the accident killed eight people, injured dozens more, and caused extensive property damage. Since then, the company has incurred (and continues to do so) significant pipeline-related expenses that were not recovered from customers. These costs are ***included*** in our earnings presentation, but a $200 million reserve PG&E took for a probable fine was excluded. All told, the company has incurred (or committed to do so) $2.7 billion in unrecovered costs. However, administrative law judges and the Safety and Enforcement Division of the California Public Utilities Commission (CPUC) are each recommending additional penalties that would raise the negative pretax impact on shareholders to more than $4.7 billion. The company is also facing an indictment from the federal government.

Earnings are tough to predict. This is due to uncertainties in the magnitude and timing of the unrecovered costs, as well as any insurance recoveries. (Note that our Earnings Predictability score includes data from years before the accident.)

Wall Street appears optimistic that this problem will be resolved without excessive harm to the company's finances. The share price rose more than 25% in 2014, and has advanced almost 10% so far in the new year.

PG&E awaits a ruling on its gas transmission and storage case. The utility requested increases of $555 million in 2015, $61 million in 2016, and $168 million in 2017. New rates will be retroactive to the start of this year. However, the discovery of some ***ex parte*** communications (via e-mail) between the company and the CPUC might well complicate this matter.

We believe more-attractive selections are available elsewhere. Following the run-up in the stock price, the dividend yield is a bit below average for a utility. The payout hasn't been raised since the accident, and we expect no hike again in 2015, even if the San Bruno matter with the CPUC is concluded before yearend. Finally, the recent price is above the upper end of our 2017-2019 Target Price Range.

Paul E. Debbas, CFA ***January 30, 2015***

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, ($2.44); '04, $6.95; '09, 18¢; '11, (68¢); '12, (15¢); gain from disc. ops.: '08, 41¢. Incl. nonrec. loss: '00, $11.83. '13 EPS don't add due to rounding. Next earnings report due mid-Feb. (B) Div'ds historically paid in mid-Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '13: $10.76/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '13: 10.4%; earned on avg. com. eq., '13: 5.9%. Regulatory Climate: Above Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	70

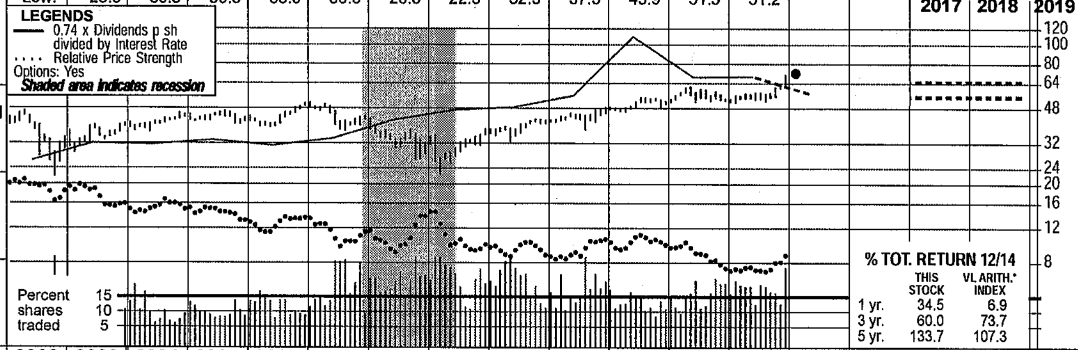
PINNACLE WEST NYSE-PNW

RECENT PRICE 71.96 | P/E RATIO 18.8 (Trailing: 19.2; Median: 15.0) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Lowered 10/10/14
SAFETY 1 Raised 5/3/13
TECHNICAL 3 Raised 12/12/14
BETA .70 (1.00 = Market)

High:	40.5	45.8	46.7	51.0	51.7	42.9	38.0	42.7	48.9	54.7	61.9	71.1		
Low:	28.3	36.3	39.8	38.3	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2		

Target Price Range 2017 | 2018 | 2019



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(-10%)	1%
Low	55	(-25%)	-2%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	160	169	171
to Sell	177	171	163
Hld's(000)	87519	87807	88791

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	34.5	6.9
3 yr.	60.0	73.7
5 yr.	133.7	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
25.12	28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	30.09	31.35	31.40	32.35	Revenues per sh	35.25
7.34	7.73	7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	7.92	8.15	8.35	8.75	"Cash Flow" per sh	9.75
2.85	3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	3.50	3.66	3.70	3.85	Earnings per sh A	4.25
1.23	1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	2.67	2.23	2.33	2.44	Div'd Decl'd per sh B ■	2.80
3.76	4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	8.24	9.36	9.10	9.55	Cap'l Spending per sh	9.25
25.50	26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	36.20	38.07	39.45	40.85	Book Value per sh C	45.50
84.83	84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	109.74	110.18	110.75	111.25	Common Shs Outst'g D	117.50
15.2	11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.4		Avg Ann'l P/E Ratio	13.5
.79	.68	.73	.61	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	.91	.86	.80		Relative P/E Ratio	.85
2.8%	3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	5.3%	4.0%	4.1%		Avg Ann'l Div'd Yield	4.8%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $3525.8 mill. **Due in 5 Yrs** $1528.1 mill.
LT Debt $3037.8 mill. **LT Interest** $159.6 mill.
Incl. $13.4 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 4.5x)
Leases, Uncapitalized Annual rentals $20.0 mill.
Pension Assets-12/13 $2264.1 mill. **Oblig.** $2646.5 mill.
Pfd Stock None

Common Stock 110,450,009 shs. **as of 10/24/14**
MARKET CAP: $7.9 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
2899.7	2988.0	3401.7	3523.6	3367.1	3297.1	3263.6	3241.4	3301.8	3454.6	3475	3600	Revenues ($mill)	4150
235.2	223.2	317.1	298.8	213.6	229.2	330.4	328.2	387.4	406.1	415	430	Net Profit ($mill)	505
35.4%	36.2%	33.0%	33.6%	23.4%	36.9%	31.9%	34.0%	36.2%	34.4%	34.0%	35.0%	Income Tax Rate	35.0%
6.9%	10.4%	11.1%	14.8%	17.5%	11.2%	11.7%	12.8%	9.7%	10.0%	10.0%	9.0%	AFUDC % to Net Profit	8.0%
46.7%	43.2%	48.4%	47.0%	46.8%	50.4%	45.3%	44.1%	44.6%	40.0%	42.0%	46.5%	Long-Term Debt Ratio	41.0%
53.3%	56.8%	51.6%	53.0%	53.2%	49.6%	54.7%	55.9%	55.4%	60.0%	58.0%	53.5%	Common Equity Ratio	59.0%
5535.2	6033.4	6678.7	6658.7	6477.6	6686.6	6729.1	6840.9	7171.9	6990.9	7545	8465	Total Capital ($mill)	9100
7535.5	7577.1	7881.9	8436.4	8916.7	9257.8	9578.8	9962.3	10396	10889	11385	11910	Net Plant ($mill)	13575
5.6%	5.0%	6.2%	5.9%	4.7%	4.8%	6.5%	6.4%	6.8%	7.1%	6.5%	6.0%	Return on Total Cap'l	6.5%
8.0%	6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.5%	9.5%	Return on Shr. Equity	9.5%
8.0%	6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	9.8%	9.7%	9.5%	9.5%	Return on Com Equity E	9.5%
2.3%	1.0%	3.4%	2.5%	.3%	.7%	3.1%	2.8%	4.1%	4.1%	3.5%	3.5%	Retained to Com Eq	3.5%
71%	85%	63%	70%	96%	89%	66%	68%	58%	58%	62%	63%	All Div'ds to Net Prof	65%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+1.8	-.2	-.2
Avg. Indust. Use (MWH)	632	647	644
Avg. Indust. Revs. per KWH (¢)	7.78	7.86	8.21
Capacity at Peak (Mw)	8577	8864	8398
Peak Load, Summer (Mw)	7087	7207	6927
Annual Load Factor (%)	50.0	48.8	50.0
% Change Customers (yr-end)	+.8	+1.3	+1.4
Fixed Charge Cov. (%)	308	397	419

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-2.0%	-2.5%	2.5%
"Cash Flow"	--	-3.0%	3.5%
Earnings	1.5%	4.0%	4.0%
Dividends	3.5%	2.5%	3.0%
Book Value	2.0%	1.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	648.9	799.8	1124.8	667.9	3241.4
2012	620.6	878.6	1109.5	693.1	3301.8
2013	686.6	915.8	1152.4	699.8	3454.6
2014	686.3	906.3	1172.7	709.7	3475
2015	700	950	1200	750	3600

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	d.15	.78	2.24	.11	2.99
2012	d.07	1.12	2.21	.24	3.50
2013	.22	1.18	2.04	.22	3.66
2014	.14	1.19	2.20	.17	3.70
2015	.20	1.25	2.20	.20	3.85

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.525	.525	.525	.525	2.10
2012	.525	.525	.525	.545	2.12
2013	.545	.545	.545	.5675	2.20
2014	.5675	.5675	.5675	.595	2.30
2015					

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.1 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 49%; commercial, 39%; industrial, 5%; other, 7%. Generating sources: coal, 33%; nuclear, 27%; gas & other, 18%; purchased, 22%. Fuel costs: 32% of revenues. Has 6,400 employees. '13 reported deprec. rate: 3.0%. Chairman, President & CEO: Donald E. Brandt. Inc.: AZ. Address: 400 North Fifth St., P.O. Box 53999, Phoenix, AZ 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary received a rate increase that took effect at the start of the new year. Arizona Public Service paid $182 million for a 739-megawatt stake in Units 4 and 5 of the Four Corners coal-fired plant. (It retired Units 1, 2, and 3.) In order to place these assets into the rate base, the utility's tariffs were raised by $57.1 million (2.0%). The increase was below the $65.4 million that APS had sought.

The utility will put forth a regulatory filing this year to address rate design. Like many utilities, APS believes customers that have installed solar panels on their buildings are not paying for their use of the electric grid. The Arizona Corporation Commission (ACC) has opened a generic docket to address this matter. The ACC has two new members, but this isn't likely to slow the regulatory process.

We estimate that earnings will increase 4% this year. The aforementioned rate increase should help. APS also receives rate relief annually for certain kinds of capital spending, such as for transmission. Customer growth is improving as the state's economy recovers from the real estate collapse that occurred several years ago. Our 2015 share-earnings estimate is at the midpoint of Pinnacle West's targeted range of $3.75-$3.95.

The utility is planning to add some gas-fired generating capacity. APS intends to build 510 mw and retire 220 mw, for net incremental capacity of 290 mw. The ACC has approved the project. The company expects the project to be completed in the second quarter of 2018 at a cost of $60 million-$70 million.

Finances are strong. The fixed-charge coverage and common-equity ratio are well above the utility norms. Earned returns on equity have improved in recent years, too.

The dividend yield of Pinnacle West stock is about average for a utility. We project that, for at least the next few years, the company will maintain the 5% annual dividend growth rate that was established last fall. However, like several other electric utility equities, the recent price is above our 2017-2019 Target Price Range. Accordingly, total return potential is negative.

Paul E. Debbas, CFA ***January 30, 2015***

(A) Diluted EPS. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from disc. ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢; '12, (5¢). '11 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid in early Mar., June, Sept., & Dec. There were 5 declarations in '12. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '13: $7.71/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '12: 10%; earned on avg. com. eq., '13: 9.9%. Regulatory Climate: Avg.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	65

PNM RESOURCES NYSE-PNM

RECENT PRICE 30.59 | P/E RATIO 20.0 (Trailing: 21.0 Median: 16.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 2.6% | VALUE LINE

TIMELINESS 2 Lowered 9/19/14
SAFETY 3 Lowered 5/9/08
TECHNICAL 3 Raised 12/5/14
BETA .85 (1.00 = Market)

High:	19.6	26.1	30.5	32.1	34.3	21.7	13.1	14.0	19.2	22.5	24.5	31.6
Low:	12.6	18.7	23.8	22.5	21.0	7.6	5.9	10.8	12.8	17.3	20.1	23.5

Target Price Range 2017 | 2018 | 2019

2017-19 PROJECTIONS

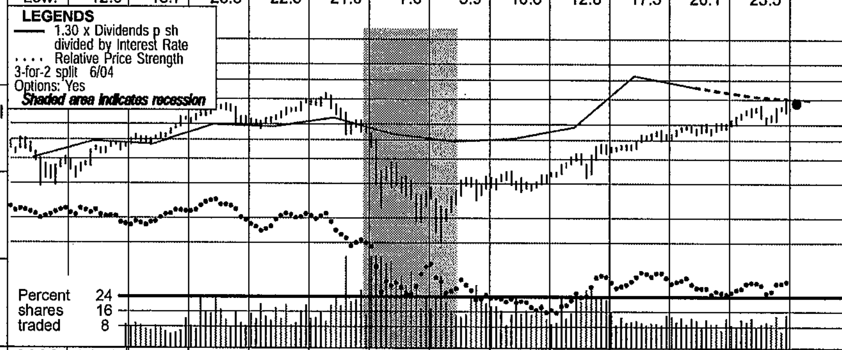
	Price	Gain	Ann'l Total Return
High	40	(+30%)	9%
Low	30	(Nil)	3%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	10	0	0	0	0	0	0	0
to Sell	0	6	0	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	91	102	86
to Sell	101	90	101
Hld's(000)	69601	69780	71291



% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.3	6.9
3 yr.	76.8	73.7
5 yr.	174.5	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
17.43	18.96	27.46	40.09	19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.85	17.42	*17.90*	*18.25*	Revenues per sh	*19.80*
3.04	2.82	3.16	4.31	2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.38	3.51	*3.65*	*3.70*	"Cash Flow" per sh	*4.60*
1.50	1.29	1.55	2.61	1.07	1.15	1.43	1.56	1.72	.76	.11	.58	.87	1.08	1.31	1.41	*1.50*	*1.55*	Earnings per sh A	*2.35*
.51	.53	.53	.53	.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.68	.74	*.80*	Div'd Decl'd per sh B ■†	*1.15*
2.06	1.56	2.50	4.51	4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.88	4.37	*4.25*	*4.75*	Cap'l Spending per sh	*4.15*
13.75	14.74	15.76	17.25	16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.05	20.87	*21.50*	*22.10*	Book Value per sh C	*24.50*
62.66	61.05	58.68	58.68	58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	79.65	79.65	*80.00*	*80.00*	Common Shs Outst'g D	*80.00*
9.8	9.5	8.5	7.3	15.1	14.7	15.0	17.4	15.6	35.6	NMF	18.1	14.0	14.5	15.0	16.1	*18.1*		Avg Ann'l P/E Ratio	*15.0*
.51	.54	.55	.37	.82	.84	.79	.93	.84	1.89	NMF	1.21	.89	.91	.95	.90	*.94*		Relative P/E Ratio	*.95*
3.5%	4.4%	4.1%	2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	3.0%	3.0%	2.7%		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $1624.1 mill. **Due in 5 Yrs** $740.1 mill.
LT Debt $1542.1 mill. **LT Interest** $120 mill.
(LT interest earned: 2.4x)
Pension Assets-12/13 $556.4 mill.
Oblig. $599.5 mill.

Pfd Stock $11.5 mill. **Pfd Div'd** $.5 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
as of 10/24/14
MARKET CAP: $2.4 billion (Mid Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
1604.8	2076.8	2471.7	1914.0	1959.5	1647.7	1673.5	1700.6	1342.4	1387.9	*1430*	*1460*	Revenues ($mill)	*1585*
88.3	106.6	122.1	59.9	8.1	53.5	80.0	96.6	105.6	113.5	*120*	*125*	Net Profit ($mill)	*190*
28.2%	31.1%	24.7%	5.1%	40.4%	30.4%	32.6%	38.8%	31.4%	31.6%	*33.0%*	*35.0%*	Income Tax Rate	*35.0%*
5.6%	15.6%	4.1%	--	--	6.4%	7.1%	8.8%	7.2%	1.3%	*1.5%*	*2.5%*	AFUDC % to Net Profit	*8.0%*
47.1%	57.4%	50.9%	42.0%	45.6%	48.7%	50.4%	51.5%	50.9%	50.0%	*51.5%*	*52.0%*	Long-Term Debt Ratio	*53.5%*
52.4%	42.3%	48.8%	57.6%	54.0%	51.0%	49.2%	48.1%	48.7%	49.7%	*48.5%*	*48.0%*	Common Equity Ratio	*46.5%*
2098.9	3044.4	3470.7	2935.8	3025.4	3214.9	3100.3	3245.6	3277.9	3344.0	*3560*	*3695*	Total Capital ($mill)	*4195*
2324.6	2984.1	3761.9	2935.4	3192.0	3332.4	3444.4	3627.1	3746.5	3933.9	*4130*	*4335*	Net Plant ($mill)	*5020*
5.3%	4.7%	4.9%	3.4%	1.9%	3.1%	4.2%	4.5%	5.1%	5.2%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.0%*
7.9%	8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	*7.0%*	*7.0%*	Return on Shr. Equity	*9.5%*
8.0%	8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.6%	6.8%	*7.0%*	*7.0%*	Return on Com Equity E	*9.5%*
4.5%	4.3%	3.7%	NMF	NMF	.4%	2.2%	3.3%	3.8%	3.7%	*3.5%*	*3.5%*	Retained to Com Eq	*5.0%*
44%	48%	49%	117%	NMF	86%	58%	47%	43%	45%	*50%*	*51%*	All Div'ds to Net Prof	*49%*

ELECTRIC OPERATING STATISTICSF

	2011	2012	2013
% Change Retail Sales (KWH)	+3.4	-1.6	-2.9
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	2547	2537	2572
Peak Load, Summer (Mw)	1938	1948	2008
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.4	+.4	+.7
Fixed Charge Cov. (%)	204	225	241

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-4.0%	-7.0%	*1.0%*
"Cash Flow"	--	5.0%	*5.5%*
Earnings	-2.5%	8.0%	*11.0%*
Dividends	0.5%	-6.0%	*12.0%*
Book Value	1.5%	-1.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	387.7	415.5	549.5	347.9	1700.6
2012	305.4	323.9	390.4	322.7	1342.4
2013	317.7	347.6	399.7	322.9	1387.9
2014	328.9	346.2	413.9	*341*	*1430*
2015	*335*	*355*	*440*	*330*	*1460*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.04	.20	.61	.22	1.08
2012	.17	.33	.69	.13	1.31
2013	.18	.38	.64	.21	1.41
2014	.18	.39	.68	*.25*	*1.50*
2015	*.25*	*.35*	*.70*	*.25*	*1.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.125	.125	.125	.125	.50
2012	.145	.145	.145	.145	.58
2013	.145	.165	.165	.165	.64
2014	.185	.185	.185	.185	.74
2015	.20				

BUSINESS: PNM Resources is an investor-owned holding company of energy and energy related businesses. Primary subsidiaries include Public Service Company of New Mexico (PNM) and Texas-New Mexico Power Company (TNMP), which generate, transmit, and distribute electricity in New Mexico and Texas. Sold First Choice Energy (9/11) and gas utility operations (1/09). Electric rev. breakdown '13: residential, 37%; commercial, 37%; industrial, 7%; other, 19%. Fuels: coal, 56.8%; nuclear, 30.4%; gas/oil, 12.2%; solar, .5%. Fuel costs: 49% of revs. '13 depr. rate: 3.0%. Has 1,924 employees. Chrmn., Pres. & CEO: Patricia K. Collawn. Inc.: NM. Address: 414 Silver Ave. SW, Albuquerque, NM. 87102. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources has filed a general rate case in New Mexico for rates to be effective January 1, 2016. The rate request, which is based on a future test year of 2016, seeks a revenue increase of $107.4 million along with a ROE of 10.5%. PNM Resources is filing the increase to address the investments the company has made to reduce its reliance on coal and additional funds needed to maintain dependable service to its retail customers. It also seeks to highlight the declining sales growth within the company's service territory. The rate base of $2.4 billion includes the costs for 40 mw of solar facilities, the 40 mw natural gas-fired La Luz plant, emission-control technology at units 1 and 4 of the San Juan generating station, the purchase of the Rio Bravo generating station natural gas plant, and the purchase of Palo Verde Unit 2 leases. The company is also recommending changes to rate design to create fair distribution of costs. If approved, the rate increase is expected to affect customers by an average increase of 7.7% across rate classes.

The board of directors recently raised the dividend. The hike was $0.015 a share, bringing the annualized dividend to $0.80 an increase of approximately 8%. PNM is targeting a payout ratio of 50%-60% over the long term.

Our 2015 share-net call is at the midpoint of the company's guidance. We expect earnings to increase modestly in 2015. The company's Texas New Mexico Power Company continues to perform well, fueled by strong economic growth within its service territory. Sales advanced by 3.2%, driven by an increase in residential and commercial categories. Although load growth in the area has been of concern recently, results in New Mexico were better than expected as residential sales increased by 1.7%. Further, PNM Resources met a significant regulatory milestone earlier in October, with the approval of the revised state implementation plan for the San Juan generating station. The New Mexico Public Regulation Commission is expected to issue a final order in the first quarter of 2015.

This stock retains a favorable Timeliness rank (2). However, the current yield is below the utility average of 3.3%

Saumya Ajila *January 30, 2015*

(A) EPS dil. Excl. n/r gains (losses): '98, (24¢); '99, 8¢; '00, 21¢; '01, (15¢); '03, 67¢; '05, (56¢); '08, ($3.77); '10, ($1.36); '11, 88¢. '13,(16); Excl. disc. ops.: '08, 42¢; '09, 78¢. Egs. may not sum due to rounding. Next egs. rpt. due late Feb. (B) Div'ds hist. pd. in Feb., May, Aug., Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '13: $3.49/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. ROE allowed in '11: 10.0%; earned on avg. com. eq., '13: 10.0%. Reg. Climate: Avg. (F) Excl. First Choice.

Company's Financial Strength	B
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	25

PORTLAND GENERAL NYSE-POR

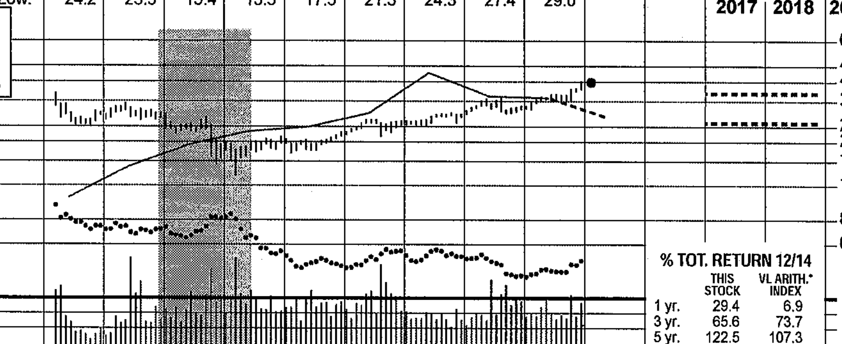
RECENT PRICE	39.76	P/E RATIO	18.2 (Trailing: 17.9; Median: NMF)	RELATIVE P/E RATIO	0.99	DIV'D YLD	2.9%	VALUE LINE

TIMELINESS 3 Lowered 12/5/14
SAFETY 2 Raised 5/4/12
TECHNICAL 3 Raised 1/9/15
BETA .80 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014
High:	35.0	31.3	27.7	21.4	22.7	26.0	28.1	33.3	40.3
Low:	24.2	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29.0

Target Price Range 2017 | 2018 | 2019

LEGENDS
— 0.74 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Percent shares traded 21 / 14 / 7

2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(-10%)	Nil
Low	25	(-35%)	-7%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	121	127	123
to Sell	116	107	116
Hld's(000)	82774	82449	83632

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	29.4	6.9
3 yr.	65.6	73.7
5 yr.	122.5	107.3

On April 3, 2006, Portland General Electric's existing stock (which was owned by Enron) was canceled, and 62.5 million shares were issued to Enron's creditors or the Disputed Claims Reserve (DCR). The stock began trading on a when-issued basis that day, and regular trading began on April 10, 2006. Shares issued to the DCR were released over time to Enron's creditors until all of the remaining shares were released in June, 2007.

2004	2005[G]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
--	23.14	24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.30	22.20	Revenues per sh	24.25
--	4.75	4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.00	5.75	"Cash Flow" per sh	6.50
--	1.02	1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.15	2.25	Earnings per sh A	2.50
--	--	.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.14	Div'd Decl'd per sh B ■ †	1.40
--	4.08	5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	13.20	6.85	Cap'l Spending per sh	3.25
--	19.15	19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.30	25.60	Book Value per sh C	29.00
--	62.50	62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.25	89.00	Common Shs Outst'g D	89.75
--	--	23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.5		Avg Ann'l P/E Ratio	12.5
--	--	1.26	.63	.98	.96	.76	.78	.89	.95	.80		Relative P/E Ratio	.80
--	--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.4%		Avg Ann'l Div'd Yield	4.4%
1454.0	1446.0	1520.0	1743.0	1745.0	1804.0	1783.0	1813.0	1805.0	1810.0	1900	1975	Revenues ($mill)	2175
92.0	64.0	71.0	145.0	87.0	95.0	125.0	147.0	141.0	137.0	170	195	Net Profit ($mill)	225
37.0%	40.2%	33.6%	33.8%	28.7%	28.8%	30.5%	28.3%	31.4%	23.2%	26.0%	24.0%	Income Tax Rate	24.0%
9.8%	18.8%	33.8%	17.9%	17.2%	31.6%	17.6%	5.4%	7.1%	14.6%	31.0%	12.0%	AFUDC % to Net Profit	4.0%
41.1%	42.3%	43.4%	49.9%	46.2%	50.3%	53.0%	49.6%	47.1%	51.3%	53.5%	45.0%	Long-Term Debt Ratio	45.5%
58.9%	57.7%	56.6%	50.1%	53.8%	49.7%	47.0%	50.4%	52.9%	48.7%	46.5%	55.0%	Common Equity Ratio	54.5%
2171.0	2076.0	2161.0	2629.0	2518.0	3100.0	3390.0	3298.0	3264.0	3735.0	4110	4140	Total Capital ($mill)	4775
2275.0	2436.0	2718.0	3066.0	3301.0	3858.0	4133.0	4285.0	4392.0	4880.0	5610	5900	Net Plant ($mill)	5875
5.6%	4.6%	4.7%	6.9%	5.0%	4.5%	5.4%	6.2%	5.9%	5.1%	5.5%	6.0%	Return on Total Cap'l	6.0%
7.2%	5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.0%	8.5%	Return on Shr. Equity	9.0%
7.2%	5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	8.2%	7.5%	9.0%	8.5%	Return on Com Equity E	9.0%
7.2%	5.3%	3.5%	6.6%	2.0%	1.5%	3.0%	4.1%	3.5%	2.9%	4.5%	4.5%	Retained to Com Eq	4.0%
--	--	39%	40%	69%	76%	62%	54%	57%	61%	51%	49%	All Div'ds to Net Prof	55%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $2321 mill. **Due in 5 Yrs** $270 mill.
LT Debt $2251 mill. **LT Interest** $104 mill.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $11 mill.

Pension Assets-12/13 $596 mill. **Oblig.** $705 mill.

Pfd Stock None

Common Stock 78,209,672 shs. as of 10/23/14

MARKET CAP: $3.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+3.3	-.8	+1.2
Avg. Indust. Use (MWH)	16573	16409	16258
Avg. Indust. Revs. per KWH (¢)	5.44	5.26	4.84
Capacity at Peak (Mw)	4162	4173	4398
Peak Load, Winter (Mw) F	3555	3597	3869
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.2	+.7	+.9
Fixed Charge Cov. (%)	273	270	239

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	--	-2.5%	.5%
"Cash Flow"	--	.5%	4.5%
Earnings	--	3.0%	5.0%
Dividends	--	4.5%	4.5%
Book Value	--	2.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	484	411	439	479	1813
2012	479	413	450	463	1805
2013	473	403	435	499	1810
2014	493	423	484	500	1900
2015	525	445	485	520	1975

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.92	.29	.36	.38	1.95
2012	.65	.34	.50	.38	1.87
2013	.65	.13	.40	.59	1.77
2014	.73	.43	.47	.52	2.15
2015	.75	.45	.50	.55	2.25

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.26	.26	.265	.265	1.05
2012	.265	.265	.27	.27	1.07
2013	.27	.27	.275	.275	1.09
2014	.275	.275	.28	.28	1.11
2015	.28				

BUSINESS: Portland General Electric Company (PGE) provides electricity to 843,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 48%; commercial, 34%; industrial, 13%; other, 5%. Generating sources: coal, 19%; gas, 16%; hydro, 16%; wind, 6%; purchased, 43%. Fuel costs: 42% of revenues. '13 reported depreciation rate: 3.7%. Has 2,600 employees. Chairman: Jack E. Davis. President and Chief Executive Officer: James J. Piro. Incorporated: Oregon. Address: 121 SW Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

A rate increase for Portland General Electric Company took effect at the start of 2015. Tariffs were raised by $15 million (about 1%), based on a return of 9.68% on a common-equity ratio of 50%. The new allowed return on equity is slightly below the previous one of 9.75%. The rate order enabled PGE to place two projects, which began commercial operation in late 2014, in the rate base. A 267-megawatt wind farm was completed at a cost that was expected to be $500 million, and a 220-mw gas-fired peaking plant was built at a cost expected to be $296 million. The rate hike was small because cost reductions and customer credits offset most of what would have been a much larger increase.

Another generating plant is under construction. The 440-mw base-load gas-fired facility is expected to begin commercial operation in mid-2016 at a cost of $450 million. PGE will file a rate application next month in order to receive rate relief in 2016. Part of the increase will take effect at the start of the year, with the remainder coming when the new plant is completed.

Following what was almost certainly its much-improved earnings tally in 2014, we estimate earnings will climb at a mid-single-digit pace this year. Our 2014 estimate is at the midpoint of PGE's targeted range of $2.10-$2.20 a share. This year, the aforementioned rate order will help boost the company's profits. In addition, PGE's service territory is experiencing load growth, despite the effects of energy efficiency measures. The industrial sector is increasing its electricity usage. Our 2015 earnings estimate is $2.25 a share.

The share count will rise significantly this year. PGE expects to settle a forward equity sale for $278 million in the second quarter. The company intends to use the proceeds to pay down borrowings from its credit facilities.

This stock's dividend yield is somewhat below the industry average. The share price has already risen 5% this year. Like several other utility equities, the recent price is ***above*** our 2017-2019 Target Price Range. Thus, total return potential is negative.

Paul E. Debbas, CFA *January 30, 2015*

(A) Diluted EPS. Excl. nonrecurring loss: '13, 42¢. Next earnings report due mid-Feb. (B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '13: $5.94/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in '15: 9.68%; earned on avg. com. eq., '13: 7.6%. Regulatory Climate: Below Average. (F) Summer peak in '12. (G) '05 per-share data are pro forma, based on shares outstanding when stock began trading in '06.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	65

SCANA CORP. NYSE-SCG

RECENT PRICE 61.27 | P/E RATIO 16.2 (Trailing: 16.2 Median: 14.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Lowered 10/10/14
SAFETY 2 Lowered 9/10/99
TECHNICAL 4 Lowered 2/13/15
BETA .75 (1.00 = Market)

High:	39.7	43.7	42.4	45.5	44.1	38.6	42.0	45.5	50.3	54.4	63.4	65.6
Low:	32.8	36.6	36.9	32.9	27.8	26.0	34.2	34.6	43.3	44.7	45.6	59.8

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

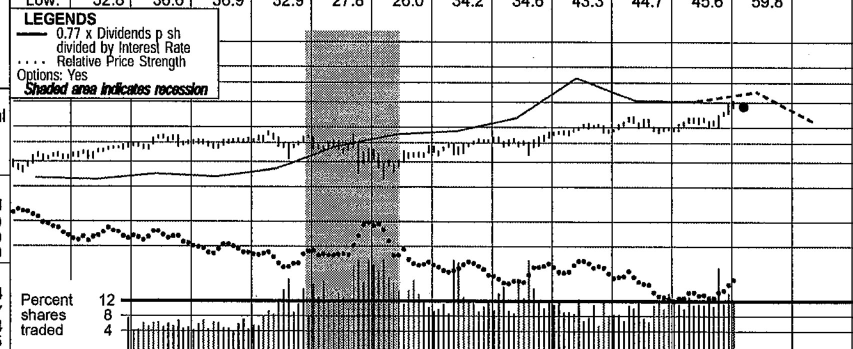
	Price	Gain	Ann'l Total Return
High	65	(+5%)	5%
Low	45	(-25%)	-3%

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	1	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	194	192	197
to Sell	153	140	154
Hld's(000)	72621	75177	77795



% TOT. RETURN 1/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	40.4	6.9
3 yr.	61.1	57.1
5 yr.	123.6	107.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
15.93	32.78	32.95	26.65	30.85	34.53	41.66	39.11	39.61	45.16	34.35	36.10	33.95	31.63	31.88	34.25	30.70	31.95	Revenues per sh	36.50
3.15	4.43	4.55	4.56	4.95	5.28	7.43	5.68	5.73	5.86	5.63	5.91	6.01	6.30	6.53	7.15	7.15	7.45	"Cash Flow" per sh	8.75
1.44	2.12	2.15	2.38	2.50	2.67	2.78	2.59	2.74	2.95	2.85	2.98	2.97	3.15	3.39	3.80	3.85	4.00	Earnings per sh A	4.75
1.32	1.15	1.20	1.30	1.38	1.46	1.56	1.68	1.76	1.84	1.88	1.90	1.94	1.98	2.03	2.10	2.16	2.22	Div'd Decl'd per sh B ■	2.40
2.37	3.28	4.99	6.41	6.94	4.86	3.38	4.52	6.21	7.68	7.41	6.87	6.81	8.16	7.84	10.30	13.20	10.60	Cap'l Spending per sh	9.75
20.27	19.40	20.95	19.64	20.82	21.78	23.35	24.39	25.37	25.85	27.63	29.05	29.94	31.47	33.08	35.05	37.00	39.00	Book Value per sh C	45.50
103.57	104.73	104.73	110.83	110.74	112.52	114.67	116.67	116.67	117.78	123.34	127.45	129.88	132.01	141.00	143.00	145.00	147.00	Common Shs Outst'g D	149.00
17.5	12.5	12.6	12.2	13.0	13.6	14.4	15.4	15.0	12.7	11.6	12.9	13.7	14.8	14.4	13.6	Bold figures are		Avg Ann'l P/E Ratio	11.5
1.00	.81	.65	.67	.74	.72	.77	.83	.80	.76	.77	.82	.86	.94	.81	.70	Value Line		Relative P/E Ratio	.70
5.2%	4.3%	4.4%	4.5%	4.2%	4.0%	3.9%	4.2%	4.3%	4.9%	5.7%	4.9%	4.8%	4.2%	4.2%	4.1%	estimates		Avg Ann'l Div'd Yield	4.3%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $6220 mill. Due in 5 Yrs $1568 mill.
LT Debt $5681 mill. LT Interest $297 mill.
(LT interest earned: 3.6x)

Leases, Uncapitalized Annual rentals $7 mill.
Pension Assets-12/13 $870.1 mill.
Oblig. $823.0 mill.
Pfd Stock None

Common Stock 142,550,214 shs.
as of 10/31/14
MARKET CAP: $8.7 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
4777.0	4563.0	4621.0	5319.0	4237.0	4601.0	4409.0	4176.0	4495.0	4900	4450	4700	Revenues ($mill)	5450
323.0	306.0	327.0	353.0	357.0	376.0	387.0	420.0	471.0	545	560	595	Net Profit ($mill)	705
--	26.5%	29.2%	35.4%	32.0%	29.8%	30.3%	30.2%	32.1%	32.0%	31.0%	31.0%	Income Tax Rate	32.0%
.9%	2.6%	4.6%	8.5%	14.3%	8.0%	5.4%	7.6%	8.7%	9.0%	18.0%	13.0%	AFUDC % to Net Profit	3.0%
51.4%	50.9%	48.4%	58.0%	56.8%	52.9%	54.3%	54.4%	53.6%	54.5%	56.0%	55.5%	Long-Term Debt Ratio	54.0%
46.6%	47.2%	49.7%	40.5%	43.2%	47.1%	45.7%	45.6%	46.4%	45.5%	44.0%	44.5%	Common Equity Ratio	46.0%
5739.0	6027.0	5952.0	7519.0	7891.0	7854.0	8511.0	9103.0	10059	11000	12150	12875	Total Capital ($mill)	14750
6734.0	7007.0	7538.0	8305.0	9009.0	9662.0	10047	10896	11643	12650	13675	14750	Net Plant ($mill)	17575
7.4%	6.8%	7.3%	6.2%	6.1%	6.5%	6.2%	6.3%	6.2%	6.5%	6.0%	6.0%	Return on Total Cap'l	6.0%
11.6%	10.3%	10.6%	11.2%	10.5%	10.2%	10.0%	10.1%	10.1%	11.0%	10.5%	10.5%	Return on Shr. Equity	10.5%
11.8%	10.5%	10.8%	11.4%	10.2%	10.2%	10.0%	10.1%	10.1%	11.0%	10.5%	10.5%	Return on Com Equity E	10.5%
5.3%	3.8%	4.0%	4.4%	3.6%	3.8%	3.6%	3.9%	4.1%	5.0%	4.5%	4.5%	Retained to Com Eq	5.0%
56%	65%	64%	62%	66%	63%	64%	61%	60%	54%	55%	55%	All Div'ds to Net Prof	51%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-3.4	-3.9	+.3
Avg. Indust. Use (MWH)	8129	8055	8180
Avg. Indust. Revs. per KWH (¢)	6.87	7.09	7.27
Capacity at Yearend (Mw)	5642	5533	5237
Peak Load, Summer (Mw)	4885	4761	4574
Annual Load Factor (%)	57.3	56.8	58.8
% Change Customers (yr-end)	+.5	+.9	+1.2
Fixed Charge Cov. (%)	279	281	293

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	.5%	-4.5%	1.5%
"Cash Flow"	3.0%	2.0%	5.0%
Earnings	3.0%	3.0%	6.0%
Dividends	4.5%	2.5%	3.0%
Book Value	4.5%	4.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	1107	908	1038	1123	4176.0
2013	1311	1016	1051	1117	4495.0
2014	1590	1026	1121	1163	4900
2015	1250	1025	1025	1150	4450
2016	1325	1075	1075	1225	4700

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.91	.54	.91	.79	3.15
2013	1.11	.60	.94	.74	3.39
2014	1.37	.68	1.01	.74	3.80
2015	1.30	.70	1.05	.80	3.85
2016	1.40	.70	1.05	.85	4.00

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.475	.485	.485	.485	1.93
2012	.485	.495	.495	.495	1.97
2013	.495	.5075	.5075	.5075	2.02
2014	.5075	.525	.525	.525	2.08
2015	.525				

BUSINESS: SCANA Corporation is a holding company for South Carolina Electric & Gas Company, which supplies electricity to 675,000 customers in South Carolina. Supplies gas and transmission service to 1.3 million customers in North and South Carolina and Georgia. Owns gas pipelines. Acquired PSNC Energy 2/00. Electric revenue breakdown: residential, 44%; commercial, 33%; industrial, 18%; other, 5%. Generating sources: coal, 48%; oil & gas, 28%; nuclear, 19%; hydro, 3%; purchased, 2%. Fuel costs: 51% of revenues. '13 reported deprec. rate: 2.9%. Has 6,000 employees. Chairman, CEO & President: Kevin B. Marsh. Incorporated: South Carolina. Address: 100 SCANA Parkway, Cayce, South Carolina 29033. Tel.: 803-217-9000. Internet: www.scana.com.

SCANA has announced the sale of two noncore subsidiaries. The company has sold its interstate gas pipeline and is selling its telecommunications business for a total of about $650 million. After taxes, the proceeds are expected to amount to more than $400 million. SCANA would use the cash in place of part of its planned equity issuances in 2015 and 2016. The company expects to record a gain on the asset sales. The telecommunications sale is likely to be completed in the current quarter.

Some delays and cost overruns are affecting the two nuclear units South Carolina Electric & Gas is building. This will provide 1,340 megawatts of capacity. The cost was estimated at $6.1 billion, but the contractors expect each unit to be delayed about a year. The contractors' schedule would have the first unit coming on line in late 2018 or early 2019, the second 12 months later. The delay will probably raise the cost by more than 10%. However, SCE&G has not accepted the revised schedule or costs, and is in talks with the contractors. Once the company has accepted a new schedule, it will have to ask the South Carolina regulators to update their previous order, which was based on a shorter construction schedule.

We estimate that earnings will increase in 2015 and 2016. Last year, favorable weather conditions made the comparisons difficult. However, we think a sharp rise in the Allowance for Funds Used During Construction, a noncash credit to earnings, will outweigh the effects of an assumed return to normal weather. Also, each year SCE&G earns a return on its additional nuclear construction work in progress.

We think the directors raised the dividend shortly after this report went to press. We estimate that the annual payout was boosted by $0.06 a share (2.9%).

The uncertainty surrounding SCE&G's nuclear construction has not hurt SCANA stock. The share price climbed 29% last year, and has risen another 1% so far in 2015. The dividend yield is only about average for a utility. The recent quotation is near the top of our 2018-2020 Target Price Range, making this issue's total return potential negligible.

Paul E. Debbas, CFA *February 20, 2015*

(A) Diluted egs. Excl. nonrec. gains (losses): '99, 29¢; '00, 28¢; '01, $3.00; '02, ($3.72); '03, 31¢; '04, (23¢); '05, 3¢; '06, 9¢. '12 & '13 EPS don't add due to rounding. Next earnings report due late April. (B) Div'ds historically paid in early Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '13: $9.65/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in SC: 10.25% elec. in '13, 10.25% gas in '05; in NC: 10.6% in '08; earned on avg. com. eq., '13: 10.7%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	100

SOUTHERN COMPANY NYSE-SO

RECENT PRICE **48.68** | P/E RATIO **17.2** (Trailing: 17.3; Median: 16.0) | RELATIVE P/E RATIO **0.93** | DIV'D YLD **4.5%** | VALUE LINE

TIMELINESS 4 Lowered 1/30/15
SAFETY 2 Lowered 2/21/14
TECHNICAL 5 Lowered 2/13/15
BETA .55 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	34.0	36.5	37.4	39.3	40.6	37.6	38.6	46.7	48.6	48.7	51.3	53.2
Low:	27.4	31.1	30.5	33.2	29.8	26.5	30.8	35.7	41.8	40.0	40.3	47.6

Target Price Range 2018 | 2019 | 2020

2018-20 PROJECTIONS

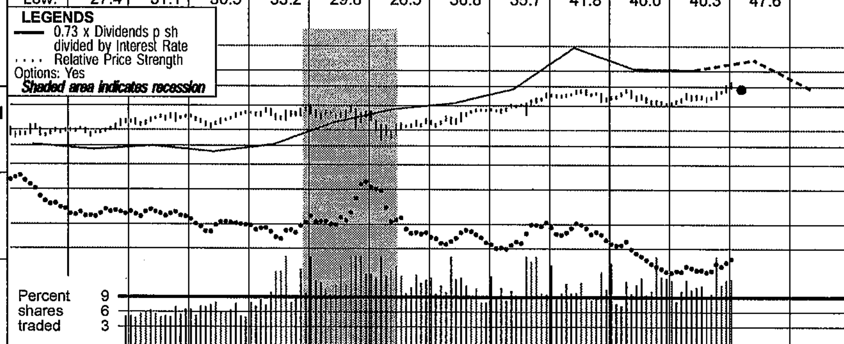
	Price	Gain	Ann'l Total Return
High	55	(+15%)	7%
Low	40	(-20%)	Nil

Insider Decisions

	M	A	M	J	J	A	S	O	N
to Buy	0	0	1	0	0	0	0	0	0
Options	0	1	2	0	2	1	1	3	1
to Sell	0	1	2	0	2	1	1	3	1

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	423	485	454
to Sell	377	342	370
Hld's(000)	435514	446155	450922



% TOT. RETURN 1/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.3	6.9
3 yr.	27.4	57.1
5 yr.	97.4	107.2

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
17.40	14.78	14.54	14.73	15.31	16.05	18.28	19.24	20.12	22.04	19.21	20.70	20.41	19.06	19.26	20.35	20.40	21.20	Revenues per sh	24.00
4.17	3.89	3.55	3.46	3.53	3.65	4.03	4.01	4.22	4.43	4.43	4.51	4.91	5.18	5.27	5.35	5.60	5.80	"Cash Flow" per sh	6.75
1.83	2.01	1.61	1.85	1.97	2.06	2.13	2.10	2.28	2.25	2.32	2.36	2.55	2.67	2.70	2.80	2.85	2.95	Earnings per sh A	3.50
1.34	1.34	1.34	1.36	1.39	1.42	1.48	1.54	1.60	1.66	1.73	1.80	1.87	1.94	2.01	2.08	2.15	2.22	Div'd Decl'd per sh B ■ †	2.43
3.85	3.27	3.75	3.79	2.72	2.85	3.20	4.01	4.65	5.10	5.70	4.85	5.23	5.54	6.16	7.90	7.45	6.00	Cap'l Spending per sh	6.50
13.82	15.69	11.43	12.16	13.13	13.86	14.42	15.24	16.23	17.08	18.15	19.21	20.32	21.09	21.43	21.90	22.60	23.30	Book Value per sh C	26.00
665.80	681.16	698.34	716.40	734.83	741.50	741.45	746.27	763.10	777.19	819.65	843.34	865.13	867.77	887.09	909.00	911.00	913.00	Common Shs Outst'g D	919.00
14.3	13.2	14.6	14.6	14.8	14.7	15.9	16.2	16.0	16.1	13.5	14.9	15.8	17.0	16.2	15.9	Bold figures are		Avg Ann'l P/E Ratio	13.5
.82	.86	.75	.80	.84	.78	.85	.87	.85	.97	.90	.95	.99	1.08	.91	.83	Value Line		Relative P/E Ratio	.85
5.1%	5.0%	5.7%	5.0%	4.7%	4.7%	4.4%	4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	4.3%	4.6%	4.7%	estimates		Avg Ann'l Div'd Yield	5.2%

CAPITAL STRUCTURE as of 9/30/14
Total Debt $24458 mill. Due in 5 Yrs $7650 mill.
LT Debt $21699 mill. LT Interest $801 mill.
(LT interest earned: 5.6x)
Leases, Uncapitalized Annual rentals $101 mill.
Pension Assets-12/13 $8733 mill. Obl. $8863 mill.
Pfd Stock $1131 mill. Pfd Div'd $68 mill.
Incl. 1 mill. shs. 4.2%-5.44% cum. pfd. ($100 par); 12 mill. shs. 5.2%-5.83% cum. pfd. ($1 par); 2 mill. shs. 6.0% noncum. pfd. ($25 par); 4 mill. shs. 5.6%-6.5% noncum. pfd. ($100 par); 14 mill. shs. 5.63%-6.5% noncum. pfd. ($1 par).
Common Stock 899,812,716 shs.
MARKET CAP: $44 billion (Large Cap)

2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		18-20
13554	14356	15353	17127	15743	17456	17657	16537	17087	18499	18600	19350	Revenues ($mill)	22000
1621.0	1608.0	1782.0	1807.0	1910.0	2040.0	2268.0	2415.0	2439.0	2584.0	2690	2795	Net Profit ($mill)	3320
26.9%	32.7%	31.9%	33.6%	31.9%	33.5%	35.0%	35.6%	34.8%	33.8%	33.0%	33.0%	Income Tax Rate	33.0%
4.4%	4.8%	9.5%	12.3%	14.9%	13.7%	10.2%	9.4%	11.6%	13.0%	12.0%	11.0%	AFUDC % to Net Profit	10.0%
53.2%	50.8%	51.2%	53.9%	53.2%	51.2%	50.0%	49.9%	51.5%	53.0%	55.5%	56.0%	Long-Term Debt Ratio	58.5%
44.3%	46.2%	44.9%	42.6%	43.6%	45.7%	47.1%	47.3%	45.8%	44.5%	42.5%	41.5%	Common Equity Ratio	39.5%
24131	24618	27608	31174	34091	35438	37307	38653	41483	44575	48725	51100	Total Capital ($mill)	60500
29480	31092	33327	35878	39230	42002	45010	48390	51208	56050	60375	63300	Net Plant ($mill)	70400
8.2%	8.2%	7.9%	7.1%	6.9%	7.0%	7.2%	7.3%	6.8%	6.5%	6.5%	6.5%	Return on Total Cap'l	6.5%
14.4%	13.3%	13.2%	12.6%	12.0%	11.8%	12.2%	12.5%	12.1%	12.5%	12.5%	12.5%	Return on Shr. Equity	13.0%
14.9%	13.8%	14.0%	13.1%	12.4%	12.2%	12.5%	12.8%	12.5%	13.0%	12.5%	13.0%	Return on Com Equity E	13.5%
4.6%	3.8%	4.3%	3.5%	3.2%	3.0%	3.4%	3.6%	3.2%	3.5%	3.0%	3.5%	Retained to Com Eq	4.5%
70%	73%	70%	74%	75%	77%	73%	73%	75%	75%	75%	75%	All Div'ds to Net Prof	69%

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	-2.7	-2.3	+.3
Avg. Indust. Use (MWH)	3438	3445	3495
Avg. Indust. Revs. per KWH (¢)	6.37	5.94	6.08
Capacity at Yearend (Mw)	43555	45750	45502
Peak Load, Summer (Mw)	36956	35479	33557
Annual Load Factor (%)	59.0	59.5	63.2
% Change Customers (yr-end)	-.1	+.5	+.7
Fixed Charge Cov. (%)	397	416	423

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '18-'20
Revenues	3.0%	-1.0%	3.0%
"Cash Flow"	4.0%	4.0%	4.0%
Earnings	4.0%	3.5%	4.0%
Dividends	3.5%	4.0%	3.5%
Book Value	5.5%	5.5%	3.0%

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	3604	4181	5049	3703	16537
2013	3897	4246	5017	3927	17087
2014	4644	4467	5339	4049	18499
2015	4250	4650	5550	4150	18600
2016	4400	4850	5800	4300	19350

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.42	.71	1.11	.43	2.67
2013	.47	.66	1.08	.49	2.70
2014	.66	.68	1.09	.38	2.80
2015	.55	.75	1.15	.40	2.85
2016	.55	.80	1.20	.40	2.95

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.455	.4725	.4725	.4725	1.87
2012	.4725	.49	.49	.49	1.94
2013	.49	.5075	.5075	.5075	2.01
2014	.5075	.525	.525	.525	2.08
2015					

BUSINESS: The Southern Company, through its subsidiaries, supplies electricity to 4.5 million customers in about 120,000 square miles of Georgia, Alabama, Florida, and Mississippi. Also has competitive generation business. Electric revenue breakdown: residential, 37%; commercial, 32%; industrial, 19%; other, 12%. Retail revenues by state: Georgia, 50%; Alabama, 34%; Florida, 9%; Mississippi, 7%. Generating sources: oil & gas, 37%; coal, 37%; nuclear, 16%; hydro, 4%; purchased, 6%. Fuel costs: 35% of revenues. '13 reported deprec. rate (utility): 3.3%. Has 26,300 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-5000. Internet: www.southerncompany.com.

Southern Company is experiencing delays and cost overruns in two subsidiaries' large capital projects. Mississippi Power's coal gasification plant was originally expected to be in service in May of 2014. Now, the expected time frame for completion is the first half of 2016. The company has already booked nonrecurring aftertax losses totaling more than $1.2 billion in the past two years. Separately, the contractor building two nuclear units at the Vogtle station has informed Georgia Power that each unit will be delayed by 18 months, to the second quarters of 2019 and 2020, respectively. However, the utility has not accepted the revised schedule, and believes the contractor has not done everything possible to mitigate the delay. Even if the contractor is ultimately responsible for the added construction costs (which have not been quantified), Georgia Power will incur related costs of $40 million for every month of delay.

The bad news has affected the stock price—just not lately. Southern Company was one of the poorest-performing utility issues in 2013. In 2014, it produced a 25% total return, which was below the 30% median for this industry. However, the equity has declined slightly so far in 2015, a performance that is in line with most other electric utilities.

Little (if any) earnings growth is likely this year. Southern Company's guidance is for $2.76-$2.88 a share, and our estimate is within this range. The first-quarter comparison is tough due to favorable weather patterns in early 2014.

We forecast an earnings increase in line with Southern Company's 3%-4% target next year. The company should benefit from rate relief, modest kilowatt-hour sales growth, and increased income at the Southern Power nonutility business.

Dividend growth is likely to continue at the same pace. Southern Company's board of directors has been raising the annual payout by $0.07 a share, and management has stated that it wants to maintain this consistency. We expect a dividend hike in the second quarter.

This untimely stock has one of the highest dividend yields of any electric company. Total return potential to 2018-2020 is only modest, however.

Paul E. Debbas, CFA *February 20, 2015*

(A) Diluted earnings. Excl. nonrecurring gain (losses): '03, 6¢; '09, (25¢); '13, (83¢); '14, (59¢). '14 EPS don't add due to rounding. Next earnings report due late Apr. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '13: $5.59/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on com. eq. (blended): 12.5%; earned on avg. com. eq., '13: 12.5%. Regulatory Climate: GA, AL Above Average; MS, FL Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	100

WESTAR ENERGY NYSE-WR

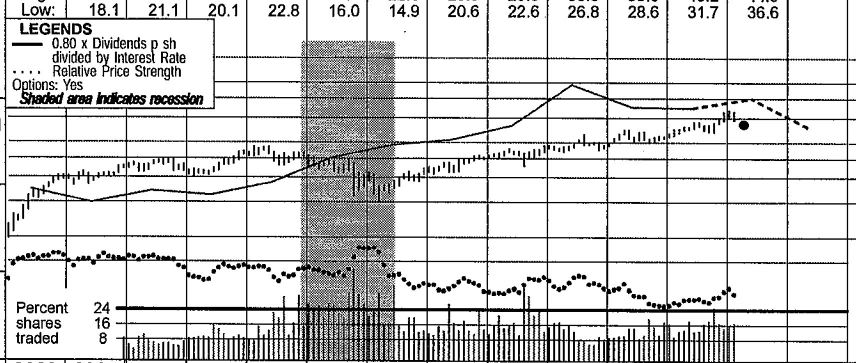
RECENT PRICE 37.20 | P/E RATIO 16.0 (Trailing: 15.8 Median: 14.0) | RELATIVE P/E RATIO 0.87 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Lowered 12/12/14
SAFETY 2 Raised 4/1/05
TECHNICAL 3 Raised 3/20/15
BETA .75 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
High:	22.9	25.0	27.2	28.6	25.9	22.3	25.9	29.0	33.0	35.0	43.2
Low:	18.1	21.1	20.1	22.8	16.0	14.9	20.6	22.6	26.8	28.6	31.7

High/Low (latest): 44.0 / 36.6

Target Price Range 2018 | 2019 | 2020



2018-20 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+35%)	11%
Low	40	(+10%)	6%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	1	0	0	1	0

Institutional Decisions

	2Q2014	3Q2014	4Q2014
to Buy	161	155	157
to Sell	116	117	136
Hld's(000)	93488	95815	96912

% TOT. RETURN 2/15

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.0	8.2
3 yr.	60.4	60.8
5 yr.	128.6	110.1

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	© VALUE LINE PUB. LLC	18-20
30.21	33.80	31.20	24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	17.88	18.48	19.76	*19.85*	*19.75*	Revenues per sh	*20.75*
7.51	6.96	5.32	4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	4.30	4.41	4.55	*4.70*	*4.95*	"Cash Flow" per sh	*5.25*
1.48	.89	d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	2.15	2.27	2.35	*2.35*	*2.55*	Earnings per sh A	*3.00*
2.14	1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	1.32	1.36	1.40	*1.44*	*1.50*	Div'd Decl'd per sh B■†	*1.65*
4.09	4.40	3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	6.40	6.08	6.47	*7.00*	*7.20*	Cap'l Spending per sh	*8.15*
27.83	27.20	25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.03	22.89	23.88	25.02	*25.60*	*26.35*	Book Value per sh C	*29.25*
67.40	70.08	70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	126.50	128.25	131.69	*130.00*	*135.00*	Common Shs Outst'g E	*140.00*
17.2	20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	13.4	14.0	15.4	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.98	1.34	--	.76	.62	.92	.79	.66	.75	1.02	.99	.83	.93	.85	.79	.81	*Value Line*		Relative P/E Ratio	*.95*
8.4%	7.9%	5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%	4.6%	4.3%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*
						1583.3	1605.7	1726.8	1839.0	1858.2	2056.2	2171.0	2261.5	2370.7	2601.7	*2580*	*2665*	Revenues ($mill)	*2800*
						134.9	165.3	168.4	136.8	141.3	203.9	214.0	275.1	292.5	313.3	*305*	*345*	Net Profit ($mill)	*420*
						31.0%	25.4%	27.5%	24.8%	29.4%	29.0%	35.2%	30.9%	33.1%	31.9%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
						--	--	10.4%	--	--	--	--	--	10.4%	10.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
						52.1%	50.0%	50.6%	49.8%	53.4%	53.6%	49.5%	51.2%	50.0%	50.0%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
						47.2%	49.3%	48.9%	49.7%	46.1%	46.0%	50.1%	48.8%	50.0%	50.0%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
						3000.4	3124.2	3738.3	4400.1	4866.8	5180.9	5531.0	5938.2	6131.1	6596.2	*6650*	*6800*	Total Capital ($mill)	*7500*
						3947.7	4071.6	4803.7	5533.5	5771.7	6309.5	6745.4	7335.7	7848.5	8441.5	*8500*	*8500*	Net Plant ($mill)	*9000*
						6.2%	6.7%	5.8%	4.2%	4.4%	5.5%	5.3%	6.0%	6.1%	6.0%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
						9.4%	10.6%	9.1%	6.2%	6.2%	8.5%	7.7%	9.5%	9.6%	9.5%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
						9.5%	10.7%	9.2%	6.2%	6.3%	8.5%	7.7%	9.4%	9.6%	9.5%	*9.5%*	*9.5%*	Return on Com Equity D	*9.5%*
						4.3%	5.5%	4.3%	1.2%	.8%	3.1%	2.7%	4.0%	4.2%	4.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
						55%	49%	53%	80%	87%	63%	65%	57%	56%	55%	*61%*	*59%*	All Div'ds to Net Prof	*55%*

CAPITAL STRUCTURE as of 12/31/14
Total Debt $3667.6 mill. **Due in 5 Yrs** $725.0 mill.
LT Debt $3382.1 mill. **LT Interest** $170.0 mill.
(LT interest earned: 2.8x)

Pension Assets 12/14 $661 mill. **Oblig.** $914 mill.

Pfd Stock None

Common Stock 132,137,563 shs.
MARKET CAP: $4.9 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2012	2013	2014
% Change Retail Sales (KWH)	-1.5	+3.6	+1.5
Avg. Indust. Use (MWH)	5588	5407	5747
Avg. Indust. Revs. per KWH (¢)	6.60	6.47	6.72
Capacity at Peak (Mw)	6557	6671	6698
Peak Load, Summer (Mw)	5411	5489	5226
Annual Load Factor (%)	56.0	55.9	56.2
% Change Customers (yr-end)	+.2	+.2	+.2
Fixed Charge Cov. (%)	319	323	332

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '12-'14 to '18-'20
Revenues	-1.0%	1.5%	*2.5%*
"Cash Flow"	1.5%	5.0%	*4.5%*
Earnings	6.5%	9.0%	*6.0%*
Dividends	3.5%	3.5%	*3.0%*
Book Value	5.0%	3.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	475.7	566.3	695.8	523.7	2261.5
2013	546.2	569.6	695.0	559.9	2370.7
2014	628.6	612.7	764.0	596.4	2601.7
2015	*630*	*620*	*750*	*580*	*2580*
2016	*650*	*645*	*775*	*595*	*2665*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2012	.21	.48	1.09	.37	2.15
2013	.40	.52	1.04	.31	2.27
2014	.52	.40	1.10	.33	2.35
2015	*.50*	*.40*	*1.10*	*.35*	*2.35*
2016	*.55*	*.45*	*1.15*	*.40*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.31	.32	.32	.32	1.27
2012	.32	.33	.33	.33	1.31
2013	.33	.34	.34	.34	1.35
2014	.34	.35	.35	.35	1.40
2015	.36				

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 700,000 customers in Kansas. Electric revenue sources: residential and rural, 34%; commercial, 38%; industrial, 28%. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2013 depreciation rate: 3.8%. Estimated plant age: 15 years. Fuels: coal, 52%; nuclear, 8%; gas, 40%. Has 2,302 employees. BlackRock Inc owns 7.0% of common; The Vanguard Group owns 5.8%; JP Morgan owns 5.2% (3/14 proxy). CEO and Pres.: Mark A. Ruelle. Inc.: Kansas. Addr.: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

Westar Energy announced 2014 results. The Topeka, Kansas-based utility posted profits of $2.35 a share for the year just ended. Higher net income was driven by greater pricing power, resulting from investments in air quality controls and transmission infrastructure. An increase in retail sales, led by industrial customers, also contributed to the underlying results.

The company filed a report to increase rates. The request was submitted in early February. Management believes that the magnitude of the investments it has made over the past few years justifies a meaningful rate increase in the upper single-digit percent range. If granted, the schedule calls for an adjustment to prices in November of this year, allowing the utility to take full advantage of the rate hike in 2016.

We expect the bottom line to be flat in 2015, followed by a strong up-tick in 2016. Our profit forecast for the current year matches the midpoint of management's share-net guidance of $2.25–$2.45. Westar Energy should continue to benefit from higher electric retail sales, driven by increasing demand from an improving business environment. Our 2016 forecast is based on the expectation of reasonable treatment from regulators, pending the submitted rate request.

The board of directors authorized a dividend increase. The quarterly distribution was raised $0.01 a share, to an annualized rate of $1.44. The yield of 3.9% is slightly above the median yield for the electric utility industry. Westar Energy is targeting a payout ratio of 50%-60%.

Capital expenditures could total $3.5 billion over the next five years. Transmission investments, the largest component, will likely exceed $1 billion. That should allow Westar to more efficiently deliver electricity to customers.

This neutrally ranked issue is a decent choice for income-oriented investors. Although future capital appreciation is muted, we think income-focused accounts would do well owning this stock for its decent dividend yield. And, the stock's lower-than-market Beta, combined with its good marks for Price Stability and Earnings Predictability, provides some added peace of mind.

Daniel Henigson *March 20, 2015*

(A) EPS diluted from 2010 onward. Excl. nonrecur. gains (losses): '98, ($1.45); '99, ($1.31); '00, $1.07; '01, 27¢; '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Earnings may not sum due to rounding. Next egs. rep't due early May. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2014: $6.48/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '14: 10.0%; earned on avg. com. eq., '14: 9.5%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	80

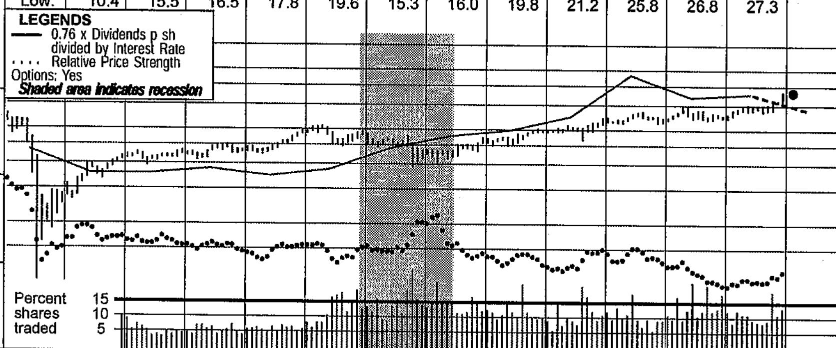
XCEL ENERGY NYSE-XEL

RECENT PRICE 37.27 | P/E RATIO 18.8 (Trailing: 19.2 Median: 14.0) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Raised 12/27/13
SAFETY 2 Raised 5/14/04
TECHNICAL 3 Lowered 1/30/15
BETA .65 (1.00 = Market)

High:	17.4	18.8	20.2	23.6	25.0	22.9	21.9	24.4	27.8	29.9	31.8	37.6
Low:	10.4	15.5	16.5	17.8	19.6	15.3	16.0	19.8	21.2	25.8	26.8	27.3

Target Price Range 2017 | 2018 | 2019



2017-19 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(-5%)	2%
Low	25	(-35%)	-5%

Insider Decisions

	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2014	2Q2014	3Q2014
to Buy	226	239	233
to Sell	212	181	189
Hld's(000)	342517	351983	351672

Percent shares traded 15 10 5

% TOT. RETURN 12/14

	THIS STOCK	VL ARITH.* INDEX
1 yr.	33.5	6.9
3 yr.	43.1	73.7
5 yr.	100.7	107.3

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	© VALUE LINE PUB. LLC	17-19
18.46	18.42	34.11	43.56	23.89	19.90	20.84	23.86	24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	*22.85*	*23.60*	Revenues per sh	*26.25*
4.30	4.13	4.12	5.09	3.14	3.35	3.27	3.28	3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	*4.20*	*4.60*	"Cash Flow" per sh	*5.25*
1.84	1.43	1.60	2.27	.42	1.23	1.27	1.20	1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	*1.95*	*2.05*	Earnings per sh A	*2.50*
1.43	1.45	1.48	1.50	1.13	.75	.81	.85	.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	*1.26*	Div'd Decl'd per sh B ■	*1.45*
2.99	13.87	3.63	7.40	6.04	2.49	3.19	3.25	4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	*5.70*	*6.65*	Cap'l Spending per sh	*5.25*
16.25	16.42	16.37	17.95	11.70	12.95	12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	*20.05*	*20.90*	Book Value per sh C	*24.00*
152.70	155.73	339.79	345.02	398.71	398.96	400.46	403.39	407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	*506.00*	*508.00*	Common Shs Outst'g D	*514.00*
15.2	16.6	14.3	12.4	NMF	11.6	13.6	15.4	14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	*16.1*		Avg Ann'l P/E Ratio	*12.5*
.79	.95	.93	.64	NMF	.66	.72	.82	.80	.89	.82	.85	.90	.89	.94	.84	*.85*		Relative P/E Ratio	*.80*
5.1%	6.1%	6.4%	5.3%	6.6%	5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%		Avg Ann'l Div'd Yield	*4.7%*

CAPITAL STRUCTURE as of 9/30/14
Total Debt $12456 mill. **Due in 5 Yrs** $3564.6 mill.
LT Debt $11502 mill. **LT Interest** $551.8 mill.
Incl. $179.4 mill. capitalized leases.
(LT interest earned: 3.5x)

Leases, Uncapitalized Annual rentals $240.7 mill.
Pension Assets-12/13 $3010.1 mill. **Oblig.** $3440.7 mill.

Pfd Stock None

Common Stock 505,685,923 shs.
as of 10/24/14
MARKET CAP: $19 billion (Large Cap)

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015		17-19
8345.3	9625.5	9840.3	10034	11203	9644.3	10311	10655	10128	10915	*11550*	*12000*	Revenues ($mill)	*13500*
526.9	499.0	568.7	575.9	645.7	685.5	727.0	841.4	905.2	948.2	*985*	*1045*	Net Profit ($mill)	*1260*
23.2%	25.8%	24.2%	33.8%	34.4%	35.1%	37.5%	35.8%	33.2%	33.8%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
10.9%	8.5%	9.8%	12.5%	15.9%	16.8%	11.7%	9.4%	10.8%	13.4%	*14.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
55.0%	51.7%	52.1%	49.7%	52.2%	51.6%	53.1%	51.1%	53.3%	53.3%	*53.0%*	*53.5%*	Long-Term Debt Ratio	*52.5%*
44.1%	47.3%	47.0%	49.4%	47.1%	47.7%	46.3%	48.9%	46.7%	46.7%	*47.0%*	*46.5%*	Common Equity Ratio	*47.5%*
11801	11398	12371	12748	14800	15277	17452	17331	19018	20477	*21650*	*22975*	Total Capital ($mill)	*25800*
14096	14696	15549	16676	17689	18508	20663	22353	23809	26122	*27875*	*29950*	Net Plant ($mill)	*34000*
6.2%	6.2%	6.2%	6.3%	6.0%	6.2%	5.7%	6.5%	6.1%	6.0%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
9.9%	9.1%	9.6%	9.0%	9.1%	9.3%	8.9%	9.9%	10.2%	9.9%	*9.5%*	*10.0%*	Return on Shr. Equity	*10.0%*
10.0%	9.2%	9.7%	9.1%	9.2%	9.4%	8.9%	9.9%	10.2%	9.9%	*9.5%*	*10.0%*	Return on Com Equity E	*10.0%*
3.9%	2.9%	3.6%	3.1%	3.8%	3.7%	3.6%	4.3%	4.7%	4.5%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
62%	69%	63%	66%	59%	61%	59%	56%	54%	54%	*61%*	*61%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2011	2012	2013
% Change Retail Sales (KWH)	+.4	-.3	+.3
Large C & I Use (MWH)	24286	24074	23875
Large C & I Revs. per KWH (¢)	5.90	5.60	6.23
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	21898	21429	21258
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.4	+.7	+.8
Fixed Charge Cov. (%)	298	303	321

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '11-'13 to '17-'19
Revenues	-3.0%	-2.0%	*3.5%*
"Cash Flow"	.5%	2.5%	*5.0%*
Earnings	3.5%	5.5%	*5.5%*
Dividends	-.5%	3.5%	*5.0%*
Book Value	2.5%	4.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	2817	2438	2832	2568	10655
2012	2578	2275	2724	2551	10128
2013	2783	2579	2822	2731	10915
2014	3203	2685	2870	*2792*	*11550*
2015	*3200*	*2750*	*3100*	*2950*	*12000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.42	.33	.69	.29	1.72
2012	.38	.38	.81	.29	1.85
2013	.48	.40	.73	.30	1.91
2014	.52	.39	.73	*.31*	*1.95*
2015	*.50*	*.44*	*.78*	*.33*	*2.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2011	.253	.253	.26	.26	1.03
2012	.26	.26	.27	.27	1.06
2013	.27	.27	.28	.28	1.10
2014	.28	.30	.30	.30	1.18
2015	.30				

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota & Michigan & gas to Minnesota, Wisconsin, North Dakota & Michigan; Public Service of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.5 mill. electric, 1.9 mill. gas. Elec. rev. breakdown: residential, 32%; sm. comm'l & ind'l, 36%; lg. comm'l & ind'l, 19%; other, 13%. Generating sources not available. Fuel costs: 47% of revs. '13 reported depr. rate: 2.9%. Has 11,600 employees. Chairman, Pres. & CEO: Ben Fowke. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

Xcel Energy's utility subsidiary in Minnesota is awaiting an order on its multiyear rate application. Northern States Power (NSP) is seeking rate hikes of $142.2 million for 2014 and $106.0 million for 2015, based on a return of 10.25% on a 52.5% common-equity ratio. (NSP is now collecting an interim tariff hike of $127 million.) An administrative law judge has recommended increases of $73.6 million in 2014 and $122.4 million in 2015, based on a 9.77% return on a 52.5% common-equity ratio. The commission's order is expected in the second quarter.
The Minnesota commission is examining the prudence of an uprate and life extension for a nuclear plant. The original estimate of this project was $320 million; the final cost was $665 million. If any portion of this spending is disallowed, Xcel would have to take a writedown.
The company is seeking electric rate hikes in other states. Public Service of Colorado is asking for an electric increase of $107.2 million, based on a return of 10.25% on a common-equity ratio of 56%. On the other hand, the commission's staff and Office of Consumer Counsel are proposing rate *decreases*. NSP filed for $15.6 million in South Dakota, based on a 10.25% return on a 53.86% common-equity ratio. Southwestern Public Service asked the Texas commission for a $64.8 million boost, based on a 10.25% return on a 53.97% common-equity ratio. Orders on each of these filings are expected in 2015.
The company received electric rate hikes in Wisconsin and Texas. NSP was granted $14.2 million in Wisconsin and $37.0 million in Texas.
Rate relief is a significant driver of Xcel's profit growth. Our 2015 earnings estimate of $2.05 a share is within the company's targeted range of $2.00-$2.15 a share.
We look for a dividend increase this quarter. We estimate that the annual payout will be raised $0.06 a share (5%), which is within Xcel's dividend growth goal of 4%-6% a year.
The dividend yield of Xcel stock is about average for a utility. Like several other utility issues, the recent price is above our 2017-2019 Target Price Range, so total return potential is negative.
Paul E. Debbas, CFA ***January 30, 2015***

(A) Diluted EPS. Excl. nonrec. gain (loss): '02, ($6.27); '10, 5¢; gains (losses) on disc. ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢. '11 & '12 EPS don't add due to rounding. Next egs. report due late Apr. (B) Div'ds histor. paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '13: $5.04/sh. (D) In mill. (E) Rate base: Varies. Rate all'd on com. eq.: MN '13 9.83%; WI '15 10.2%; CO '14 (elec.) 9.72%; CO '07 (gas) 10.25%; TX '14 10.4%; earned on avg. com. eq., '13: 10.3%. Regulatory Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	100

Society of Utility and
Regulatory Financial Analysts

THE COST OF CAPITAL –

A PRACTITIONER'S GUIDE

BY

DAVID C. PARCELL

PREPARED FOR THE SOCIETY OF UTILITY AND REGULATORY FINANCIAL ANALYSTS (SURFA)

2010 EDITION

Author's Note: This manual has been prepared as an educational reference on cost of capital concepts. Its purpose is to describe a broad array of cost of capital models and techniques. No cost of equity model or other concept is recommended or emphasized, nor is any procedure for employing any model recommended. Furthermore, no opinions or preferences are expressed by either the author or the Society of Utility and Regulatory Financial Analysts.

CHAPTER 7
COMPARABLE EARNINGS

The comparable earnings method ("CE" or "CEM") is the "granddaddy" of cost of equity methods, as it is derived from the "corresponding risk" standard of the *Bluefield* and *Hope* cases. This method is based upon the economic concept of "opportunity cost." As noted previously the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk. If, in the opinion of those who save and commit capital, the prospective return from a given investment is not equal to that available from other investments of similar risk, the available capital will tend to be shifted to the alternative investments. Through this mechanism, opportunity-cost-driven pricing signals direct capital to its most productive uses; thus, a free enterprise system promotes an efficient allocation of scarce resources.

The established legal standards are consistent with the opportunity cost principle. The two Supreme Court cases most frequently cited (*Bluefield* and *Hope*) hold that: the return to the equity owners be sufficient to maintain the credit of the enterprise and confidence in its financial integrity; to permit the enterprise to attract required additional capital on reasonable terms; and, to provide the enterprise and its investors with an earnings opportunity commensurate with the returns available on investments in other enterprises having corresponding risks.

These three interrelated criteria constitute a succinct statement of the opportunity cost principle. An expected return on equity equal to that which can be realized on alternative investments of corresponding risk will, in turn, be sufficient to assure confidence in the financial integrity of the enterprise, to maintain its credit, and to permit it to attract new capital on reasonable terms.

The comparable earnings method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, since it translates into practice the competitive principle upon which regulation rests.

The comparable earnings method normally examines the experienced and/or projected returns on book common equity. The logic for returns on book equity follows from the use of original cost rate base regulation for public utilities which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base – rate of return methodology used to set utility rates.

It is maintained that the comparable earnings standard is easy to calculate and the amount of subjective judgment required is minimal. The method avoids several of the subjective factors involved in other cost of capital methodologies. For example, the DCF method requires the determination of the growth rate contemplated by investors, which is a subjective factor. The CAPM requires the specification of several expectational variables, such as market return and beta. In contrast, the comparable earnings approach makes use of readily available accounting data.

In addition, this method is easily understood and is firmly anchored in regulatory tradition (i.e., *Bluefield* and *Hope*). The method is not influenced by the regulatory process to the same extent as market-based methods such as DCF and CAPM. The base to which the comparable earnings standard is applied is the utility's book common equity, which is much less vulnerable to regulatory influences than stock price which is the base to which the market-based standards are applied. Stock price can be influenced by the actions of regulators.

The rationale for the comparable earnings technique is aptly stated by Morin (2006, 394):

> "Although the Comparable Earnings test does not square well with economic theory, the approach is nevertheless meritorious. If the basic purpose of comparable earnings is to set a fair return rather than determine the true economic return, then the argument is academic. If regulators consider a fair return as one that equals the book rates or return earned by comparable risk firms rather than one that is equal to the cost of capital of such firms, the Comparable Earnings test is relevant. This notion of fairness, rooted in the traditional legalistic interpretation of the *Hope* language, validates the Comparable Earnings test."

NEW REGULATORY FINANCE

Roger A. Morin, PhD

2006
PUBLIC UTILITIES REPORTS, INC.
Vienna, Virginia

the earnings requirement of utilities is determined by applying a percentage rate of return to the book value of a utility's investment, and not on the market value of that investment. Therefore, it stands to reason that a different percentage rate of return than the market cost of capital be applied when the investment base is stated in book value terms rather than market value terms. In a competitive market, investment decisions are taken on the basis of market prices, market values, and market cost of capital. If regulation's role was to duplicate the competitive result perfectly, then the market cost of capital would be applied to the current market value of rate base assets employed by utilities to provide service. But because 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.

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SYM	Company	ROE 2017-19
ALE	ALLETE	9.0%
LNT	Alliant Energy	12.0%
AEE	Ameren Corp.	9.5%
AEP	American Elec Pwr	10.0%
AVA	Avista Corp.	8.5%
BKH	Black Hills Corp.	9.0%
CNP	CenterPoint Energy	15.0%
CNL	Cleco Corp.	9.5%
CMS	CMS Energy Corp.	13.5%
ED	Consolidated Edison	9.0%
D	Dominion Resources	17.0%
DTE	DTE Energy Co.	9.5%
DUK	Duke Energy Corp.	8.0%
EIX	Edison International	11.0%
EE	El Paso Electric	9.0%
EDE	Empire District Elec	9.0%
ETR	Entergy Corp.	10.5%
ES	Eversource Energy	9.5%
EXC	Exelon Corp.	9.5%
FE	FirstEnergy Corp.	8.0%
GXP	Great Plains Energy	7.5%
HE	Hawaiian Elec.	10.0%
IDA	IDACORP, Inc.	8.5%
TEG	Integrys Energy Group	8.5%
ITC	ITC Holdings Corp.	17.5%
MGEE	MGE Energy	13.5%
NEE	NextEra Energy, Inc.	12.0%
NWE	NorthWestern Corp.	9.5%
OGE	OGE Energy Corp.	12.0%
OTTR	Otter Tail Corp.	12.5%
POM	Pepco Holdings	10.0%
PCG	PG&E Corp.	9.5%
PNW	Pinnacle West Capital	9.5%
PNM	PNM Resources	9.5%
POR	Portland General Elec.	9.0%
PPL	PPL Corp.	10.0%
PEG	Pub Sv Enterprise Grp	10.5%
SCG	SCANA Corp.	10.5%
SRE	Sempra Energy	11.5%
SO	Southern Company	13.5%
TE	TECO Energy	12.0%
UIL	UIL Holdings	10.0%
VVC	Vectren Corp.	14.0%
WR	Westar Energy	9.5%
WEC	Wisconsin Energy	15.0%
XEL	Xcel Energy Inc.	10.0%
	Average	10.68%

The Value Line Investment Survey (Dec. 19, 2014, Jan. 30 & Feb. 20, 2015).

NEW REGULATORY FINANCE

Roger A. Morin, PhD

2006
PUBLIC UTILITIES REPORTS, INC.
Vienna, Virginia

securities to the point at which new purchases would earn only the old cost of capital on their investments. The only beneficiaries would be those who happened to own the stock at the time the policy change was announced or anticipated.

12.5 M/B Ratios in the Regulatory Process

It is sometimes argued that because current M/B ratios are in excess of 1.0, this indicates that companies are expected by investors to be able to earn more than their cost of capital, and that the regulating authority should lower the authorized return on equity, so that the stock price will decline to book value. It is therefore plausible, under this argument, that stock prices drop from the current M/B value to the desired M/B ratio range of 1.0 times book.

There are several reasons why this view of the role of M/B ratios in regulation should be avoided.

(1) The inference that M/B ratios are relevant and that regulators should set an ROE so as to produce an M/B of 1.0 is misguided. The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce an M/B of 1.0 presumes that investors are irrational. They commit capital to a utility with an M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is certainly not a realistic or accurate view of regulation. For example, assume a utility company with an M/B ratio of 1.5. If investors expect the regulator to authorize a return on book value equal to the DCF cost of equity, the utility stock price would decline to book value, inflicting a capital loss of some 30%. The notion that investors are willing to pay a price of 1.5 times book value only to see the market value of their investment drop by 30% is irrational.

(2) The condition that the M/B will gravitate toward 1.0 if regulators set the allowed return equal to capital costs will be met only if the actual return expected to be earned by investors is at least equal to the cost of capital on a consistent long-term basis and absent inflation. The cost of capital of a company refers to the expected long-run earnings level of other firms with similar risk. If investors expect a utility to earn an ROE equal to its cost of equity in each period, then its M/B ratio would be approximately 1.0 or higher with the proper allowance for flotation cost.

(3) A company's achieved earnings in any given year are likely to exceed or be less than their long-run average. Depressed or inflated M/B ratios are to a considerable degree a function of forces outside the control of regulators, such as the general state of the economy, or general economic or financial circumstances that may affect the yields on securities of unregulated as well

as regulated enterprises. The achievement of a 1.0 M/B ratio is appropriate, but only in a long-run sense. For utilities to exhibit a long-run M/B ratio of 1.0, it is clear that during economic upturns and more favorable capital market conditions, the M/B ratio must exceed its long-run average of 1.0 to compensate for the periods during which the M/B ratio is less than its long-run average under less favorable economic and capital market conditions.

Historically, the M/B ratio for utilities has fluctuated above and below 1.0. It has been consistently above 1.0 from the 1980s to the mid 2000s. This indicates that earnings below capital costs and M/B ratios below 1.0 during less favorable economic and capital market conditions must necessarily be accompanied with earnings in excess of capital costs and M/B ratios above 1.00 during more favorable economic and capital market conditions.

M/B ratios are determined by the marketplace, and utilities cannot be expected to compete for and attract capital in an environment where industrials are commanding M/B ratios well in excess of 1.0 while regulation reduces their M/B ratios toward 1.0. Moreover, if regulators were to currently set rates so as to produce an M/B ratio of 1.0, not only would the long-run target M/B ratio of 1.0 be violated, but more importantly, the inevitable consequence would be to inflict severe capital losses on shareholders. Investors have not committed capital to utilities with the expectation of incurring capital losses from a misguided regulatory process.

(4) Rate of return regulation is fundamentally a surrogate for competition. The fundamental goal of regulation should be to set the expected economic profit for a public utility equal to the level of profits expected to be earned by firms of comparable risk, in short, to emulate the competitive result. For unregulated firms, the natural forces of competition will ensure that in the long run, the ratio of the market value of these firms' securities equals the replacement cost of their assets. Competitive industrials of comparable risk to utilities have consistently been able to maintain the real value of their assets in excess of book value, consistent with the notion that, under competition, the Q-ratio will tend to 1.00 and not the M/B ratio. This suggests that a fair and reasonable price for a public utility's common stock is one that produces equality between the market price of its common equity and the replacement cost of its physical assets. The latter circumstance will not necessarily occur when the M/B ratio is 1.0. As the previous section demonstrated, only when the book value of the firm's common equity equals the value of the firm's equity at replacement assets will equality hold.

In an inflationary period, the replacement cost of a firm's assets may increase more rapidly than its book equity. To avoid the resulting economic confiscation of shareholders' investment in real terms, the allowed rate of return should produce an M/B ratio which provides a Q-ratio of 1 or a Q-ratio equal to that of comparable firms. It is quite plausible and likely that M/B ratios will exceed one if inflation increases the replacement cost of a firm's assets at a faster pace than historical cost (book equity). Perhaps this explains in part why utility M/B ratios have remained well above 1.0 over the past two decades. Are we to conclude that regulators have been systematically misguided all across the United States for all these years by awarding overgenerous returns, or are we to conclude that M/B ratios are largely immaterial in the context of ratemaking? The latter is more likely.

Historically, it has been highly unusual for utility stock prices to equal book value. Stock prices above book value are common for utility stocks, and indeed for all of the major market indexes. It is obvious that regulators, through their rate case decisions, and investors do not subscribe to the notion that utilities that have market prices above book value are over-earning. Otherwise, regulators would not grant rate increases for any utility whose stock price was above book value, and investors would never bid up the price of stock above book value. It is very difficult to accept the notion that, in a free-market economy with rampant competition, the vast majority of all publicly traded-stocks are earning well in excess of their cost of capital.

In short, economic principles do not support the notion that the market value of utility shares should necessarily equal book value. A basic economic principle holds that, in the long run, market value should equal asset replacement cost in a given industry. In the presence of inflation and absent significant technological advances, replacement cost exceeds the original cost book value of assets. Consequently, it is quite reasonable for the market value of utility shares to exceed their book value and there is no reason to conclude that market value should equal book value when one recognizes that regulation is intended to emulate competition.

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MOODY'S
INVESTORS SERVICE

US Regulated Utilities

Regulation Will Keep Cash Flow Stable As Major Tax Break Ends

Our outlook for the US regulated utility industry is stable. This outlook reflects our expectations for the fundamental business conditions in the industry.

» **Cost-recovery mechanisms, coupled with annual base-rate increases, will keep the ratio of industry-wide cash flow to debt at about 18%, within our range for a stable outlook.** Favorable rate orders are part of what we view as a broader shift toward stronger regulatory support for the industry, all the more important this year given the end of bonus depreciation. Industry regulation is the most important driver of our outlook.

» **Ratemaking mechanisms, such as revenue decoupling and riders, allow utilities to recover costs faster and improve the quality, predictability and stability of cash flow.** The ratio of cash flow to gross profit for a peer group of 122 US operating companies has been more stable on a year-over-year basis since 2009, as the use of riders in regulatory agreements has become more commonplace.

» **We are also seeing signs of improved regulatory support in historically contentious states, such as Connecticut and Illinois.** Stronger recovery mechanisms put in place last year for Connecticut Natural Gas Corp. (A3 stable) and Commonwealth Edison Co. (Baa1 stable) in Illinois will likely make cash flow more predictable for utilities in each state. This marks a turnaround in both states, where regulatory support was lacking for certain cost-recovery provisions in the past.

» **Stagnant customer demand is leading some utilities to pursue shareholder growth through financial engineering.** Some companies are restructuring their businesses by creating master limited partnerships and "yieldcos" to defend their historically high equity multiples. For now, credit risks are limited but so are any benefits for bondholders, and these structures may weaken sponsor credit quality over time.

» **What could change our outlook.** We could shift our outlook to positive if the ratio of cash flow to debt rose toward 25% on a sustainable basis, which could happen if return on equity rises or utilities deleverage significantly. A more contentious regulatory environment that resulted in a material deterioration in cash flow, such that the ratio fell to 13%, could cause us to have a negative outlook.

Supportive regulatory relationships drive our stable outlook

Regulatory support will help US electric and gas utilities maintain stable credit profiles in 2014, even with stagnant customer demand and without the cash-flow boost from bonus depreciation.

Fundamentally, the regulatory environment is the most important driver of our outlook because it sets the pace for cost-recovery. Favorable rate orders, even in states where utilities have had contentious regulatory relationships in the past, are part of what we view as a broader shift toward stronger regulatory support for the industry.

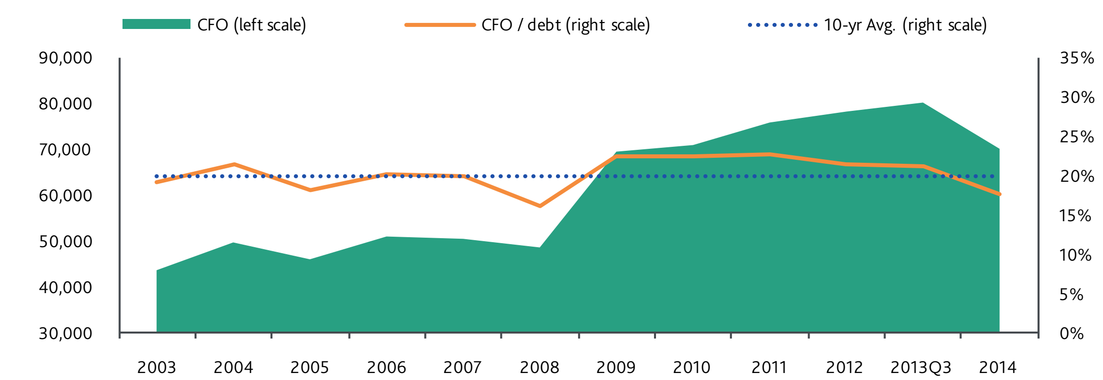
The improved regulatory framework, led by special cost-recovery mechanisms and annual base-rate increases, is all the more important this year for two reasons. First is the end of bonus depreciation, a temporary tax break that expired on December 31. We incorporate a view that bonus depreciation will not be extended; however, various corporate sectors are currently lobbying for the extension in 2014. Second is stagnant customer demand, which is also leading some utilities to pursue shareholder growth through financial engineering (please see page 6).

As Exhibit 1 shows, the ratio of cash flow to debt will decline this year to 18%, just below the 10-year trend line but within our range for a stable outlook. The decline is largely because of higher cash taxes, but utilities can still get some tax relief in 2014 by applying net operating loss carry-forwards (from factors unrelated to bonus depreciation) from past years to this year's tax payments—an option they didn't use when bonus depreciation was in effect.

We would likely shift our outlook to positive if the ratio of cash flow to debt rose to 25%, although that would take a marked increase in regulatory-allowed ROE levels or steps by utilities to scale back their dividend and stock-repurchase plans. A more contentious regulatory environment or a widespread adoption of more-aggressive financial strategies resulting in a material deterioration in cash flow, such that the ratio fell to 13%, would likely lead to a negative outlook.

EXHIBIT 1

Cash Flow to Debt Will Hover Below the 10-Year Average



Notes: Figures are in thousands of US dollars. A list of the 122 utilities included in our analysis starts on page 7. Data for the third quarter of 2013 are the latest available. Data for 2014 are our estimates.
Source: Moody's Investors Service

Improved regulatory environment means stable, more predictable cost-recovery

The US regulatory environment has improved significantly in the past year, providing for faster and more-certain cost-recovery in 2014.

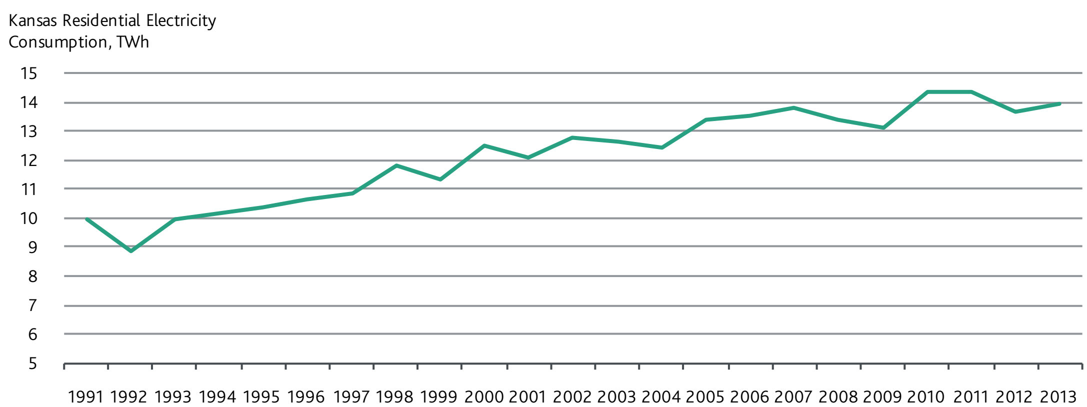
Puget Sound Energy Inc.'s (PSE; Baa1 stable) June 2013 rate order is a good example. Its regulator, the Washington Utilities and Transportation Commission, approved the decoupling of electric and gas revenue from sales volume, and a property-tax tracker that provides more-efficient recovery of property-tax expense. The commission acknowledged a need to reduce regulatory lag times by expediting the utility's rate filings and offering more real-time true-up of costs during rate filings. The regulator also provided the company with forward-looking annual revenue adjustments (about 3% for electric and 2% for gas) over the next three years. As a result of these changes, we expect that Puget Sound's cash-flow-to-debt ratio will continue to surpass 20%, exceeding the industry average, even without the cash-flow benefit of bonus depreciation.

Another example is Westar Energy Inc.'s (Baa1 stable) 2013 abbreviated rate case with the Kansas Corporation Commission. In addition to providing incremental cost-recovery for environmental upgrades, the regulator allowed Westar to increase its monthly fixed charge on customer bills. This movement in rate design will allow Westar to recover a greater portion of its fixed costs through fixed rates, rather than volumetric rates, thereby reducing Westar's dependency on selling higher volumes to recover fixed costs. The shift to a $12 residential monthly fixed charge from $9 will be a benefit amid flat customer demand in Kansas over the past three years (see Exhibit 2).

EXHIBIT 2

Demand for Electricity Has Been Stagnant in Kansas

Actual Consumption



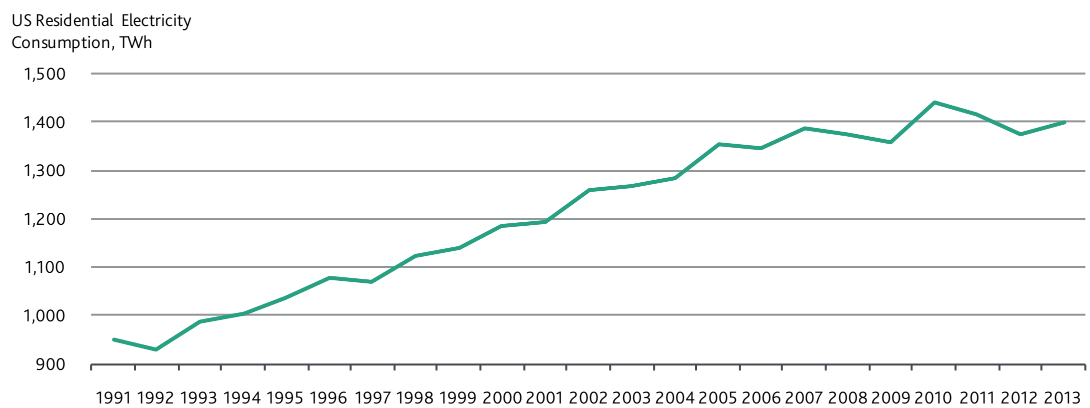
Notes: TWh stands for terawatt hour. 2013 US Energy Information Administration (EIA) data are through October 2013. Our estimates for November and December 2013 are based on historical trends.
Source: US Energy Information Administration

As demand for electricity wanes, rate structures that are tied more closely to volumetric charges than to fixed charges will threaten the gross profits of most electric and gas utilities. Exhibit 3 below shows the drop-off in US electricity demand since 2010, largely attributable to weather and slow economic growth as well as conservation and efficiency measures.

EXHIBIT 3

Demand for Electricity Is Slow to Rebound

Actual Consumption



Note: 2013 EIA data is through October 2013. Our estimates for November and December 2013 are based on historical trends.
Source: US Energy Information Administration

The industry's financial profile is becoming more predictable and steady because of these special recovery mechanisms that supplement cash recovery between general rate cases. As Exhibit 4 shows, the average ratio of cash flow from operations to gross profit had a standard deviation of 2.4% on a year-over-year basis between 2003 and 2008. This compares with a 1.1% standard deviation on average between 2009 and the third quarter of 2013, the latest data available, a period marked by a more pervasive use of cost-recovery mechanisms throughout the US.

EXHIBIT 4

Cost-Recovery Mechanisms Make Cash Flow More Predictable

Year	CFO / Gross Profit	Standard Deviation Rolling Two-Year Average	Average Standard Deviation
2003	30.9%		
2004	37.0%	4.3%	
2005	34.0%	2.1%	
2006	37.3%	2.4%	
2007	34.9%	1.7%	
2008	32.9%	1.4%	2.4%
2009	44.9%		
2010	42.5%	1.7%	
2011	44.8%	1.6%	
2012	44.3%	0.3%	
3Q13	43.0%	0.9%	1.1%

Note: The latest data available are for the third quarter of 2013.
Source: Moody's Investors Service

Cost-recovery improves, but not without exceptions

Most regulated electric and gas utilities in the US have shown evidence of improved regulatory relationships. Apart from Puget Sound's and Westar's cost-recovery improvements, we have seen regulatory improvement in Illinois and Connecticut, states in which the relationships between regulators and utilities have been somewhat contentious.

Stronger recovery mechanisms put in place late last year in both Illinois and Connecticut will make utility cash flow more predictable. For example, in Illinois, **Commonwealth Edison**'s (ComEd) cash flow to debt coverage will start improving in 2014, supported by the adoption of a version of formula ratemaking (i.e., the Energy Infrastructure Modernization Act, or "EIMA," which helps define various aspects of rate structure and cost-recovery in Illinois). The implementation of EIMA will make cost-recovery more tied to factors determined by a formula and less tied to rate-case negotiations (the results of which are less predictable).

Similarly, the Connecticut legislature in 2013 passed the Comprehensive Energy Strategy, which encourages the use of decoupling mechanisms and infrastructure replacement riders (i.e., the Distribution Integrity Management Program, or DIMP), while promoting growth of local distribution companies (LDCs) through customer conversions. These measures are subject to approval by the Public Utilities Regulatory Authority in rate-case proceedings, but were approved in **Connecticut Natural Gas**'s (CNG; A3 stable) December 2013 rate case. We expect decoupling, DIMP and conversion incentives to be applied to all LDCs in the state going forward.

These moves mark a turnaround in both states from past years, when regulatory support was lacking for certain cost-recovery provisions and when general rate case outcomes were deemed less than favorable from an investor perspective. For example, the Illinois legislature passed the EIMA in 2011, but the Illinois Commerce Commission did not fully implement it, initially, which made future cost-recovery for ComEd uncertain. Likewise, Connecticut LDCs had few tracking mechanisms and were exposed to declining customer usage in rate design. Now, through the adoption of EIMA in ComEd's rate structure (clarified by Senate Bill 9 in 2013) and CNG's implementation of decoupling and the DIMP, the financial profiles of both companies will likely improve.

These cost-recovery improvements are part of the broader trend we are seeing in the industry, but there are a few high-profile exceptions. Entergy Corp. (Baa3 stable), which has a history of contentious regulatory relationships in Arkansas and Texas, is one example.

Last year, Entergy Arkansas Inc. (Baa2 stable) put forth a nearly $145 million rate request but received about $81 million (the Arkansas Public Service Commission did allow a new cost-recovery rider for certain regional transmission expenses, however). Entergy Texas Inc. (Baa3 stable) requested about $53 million in rate increases for 2014, but the Texas Public Utilities Commission's (PUC) staff recommended a rate increase of a little more than $3 million. The PUC has not issued a final decision.

Another high-profile exception is Consolidated Edison of New York's (A2 stable) pending rate settlement, which calls for a two-year freeze on electric rates and a three-year rate freeze on gas and steam rates. Although the rate freeze would curb Consolidated Edison of New York's earnings, the settlement is credit neutral because of the provision for reasonable recovery of deferred storm costs related to Hurricane Sandy and other investments.

This year, one utility that might also buck the positive trend is Jersey Central Power & Light Co. (JCP&L; Baa2 negative). JCP&L has been the target of public criticism over its handling of outages related to Hurricane Sandy, besides allegations of over-earning. The staff of the New Jersey Board of Public Utilities has proposed that base rates be cut by $207 million (not considering recovery of storm costs, which will be addressed in a separate rate proceeding). This compares with the company's request for an increase of $11 million (again, not considering storm costs).

JCP&L's financial flexibility and financial metrics have already been weakened by costs associated with Hurricane Sandy, so a material rate reduction could hurt JCP&L's rating. If JCP&L can bring its ratio of cash flow to debt to at least 14% despite a rate decrease, then our rating outlook could stabilize. JCP&L had 12% cash flow to debt through the 12 months ended the third quarter of 2013.

More utilities are turning to financial engineering

Against a backdrop of stagnant demand, some utility holding companies are turning to forms of financial engineering, such as creating master limited partnerships (MLPs) and so-called yieldcos, to defend their historically high equity multiples. For the few companies that have proceeded with these strategies so far, the credit impact is neutral because the vehicles are small relative to the corporate sponsor's consolidated credit profile. But longer term, credit risks could increase if these companies eventually lose too much cash flow from their most stable assets and don't reduce debt enough to rebalance their capital structures.

We expect some more companies to go public with these financial-engineering vehicles this year. The joint venture among OGE, CenterPoint and ArcLight—the Enable Midstream Partners MLP—plans to complete an initial public offering in the first quarter. Dominion Resources Inc. (Baa2 stable) expects to publicly offer its MLP by mid-year. In addition, NextEra Energy Inc. (Baa1 stable) expects to make a decision whether to form a yieldco by then.

Meantime, several companies have pursued acquisitions outside of their core utility holdings and service territories, like MidAmerican Energy Holdings Co. (A3 stable), TECO Energy Inc. (Baa1 stable), and Avista Corp. (Baa1 stable). This trend is bound to continue as companies try to expand their regulated footprint and achieve regulatory diversity. We expect that most M&A activity in 2014 will be conservatively financed much like these transactions, which included equity financings.

EXHIBIT 5

Regulated Utilities: M&A Activity

	Acquirer			Acquiree				
Acquirer / Acquiree	Revenue	CFO	Debt	Revenue	CFO	Debt	Financing	Credit Implication
MidAmerican Energy Holdings Co. / NV Energy, Inc.	$12,373	$505	$4,255	$2,930	$794	$5,125	$5.6 billion in debt & equity	Positive; no ratings actions
TECO Energy, Inc. / New Mexico Gas Company	$2,851	$680	$3,156	$332	$65	$250	$950 million in debt, equity, & cash	Affirmed TECO Energy ratings
Avista Corp / Alaska Energy and Resources Company (AERC)	$1,581	$295	$1,739	$42	$20	$115	$170 million in equity	Neutral for Avista
Fortis, Inc. / UNS Energy Corporation	$3,654	$976	$5,783	$1,483	$400	$ 1,937	$4.3 billion in debt & equity	Slightly positive for UNS Energy Corporation; no ratings action

Notes: Financials are in millions, as of the 12 months ended September 30, 2013. AERC financials are based on Alaska Electric Light and Power Co. (AELP) 2012 FERC Form 1 data. Fortis and New Mexico Gas financials are as reported as of fiscal 2012. We expect TECO Energy will assume $200 million of debt already existing at New Mexico Gas Company. We expect Fortis to assume approximately $1.8 billion of debt already existing at UNS Energy Corporation. In addition, we expect Fortis to finance the UNS acquisition in a manner similar to historical precedent, with a balanced mix of debt and equity issued upstream from the utility (we expect Fortis to keep UNS's current capital structure in place).
Sources: Fortis Inc. Annual Report, AELP 2012 FERC Form 1, SNL, Moody's Financial Metrics

Appendix: Peer Group

Moody's Financial Metrics

	Entity Name	LT Rating	Outlook	CFO/Debt (3-Yr Avg) LTM 3Q11-LTM3Q13
Integrated	Alabama Power Company	A1	Stable	26%
	ALLETE, Inc.	A3	Stable	22%
	Appalachian Power Company	Baa1	Stable	17%
	Arizona Public Service Company	A3	Stable	28%
	Avista Corp.	Baa1	Stable	18%
	Black Hills Power, Inc.	A3	Stable	22%
	Cleco Power LLC	Baa1	Positive	19%
	Consumers Energy Company	(P)A3	Stable	27%
	Dayton Power & Light Company	Baa3	Stable	34%
	DTE Electric Company	A2	Stable	24%
	Duke Energy Carolinas, LLC	A1	Stable	23%
	Duke Energy Corporation	A3	Stable	15%
	Duke Energy Florida, Inc.	A3	Stable	21%
	Duke Energy Indiana, Inc.	A2	Stable	16%
	Duke Energy Kentucky, Inc.	Baa1	Stable	23%
	Duke Energy Ohio, Inc.	Baa1	Stable	25%
	Duke Energy Progress, Inc.	A1	Stable	23%
	El Paso Electric Company	Baa1	Stable	25%
	Empire District Electric Company (The)	Baa1	Stable	20%
	Entergy Arkansas, Inc.	Baa2	Stable	19%
	Entergy Louisiana, LLC	Baa1	Stable	17%
	Entergy Mississippi, Inc.	Baa2	Stable	16%
	Entergy New Orleans, Inc.	Ba2	Stable	20%
	Entergy Texas, Inc.	Baa3	Stable	14%
	Florida Power & Light Company	A1	Stable	32%
	Georgia Power Company	A3	Stable	25%
	Gulf Power Company	A2	Stable	26%
	Hawaiian Electric Company, Inc.	Baa1	Stable	17%
	Idaho Power Company	A3	Stable	16%
	Indiana Michigan Power Company	Baa1	Stable	21%
	Interstate Power and Light Company	A3	Stable	18%
	Kansas City Power & Light Company	Baa1	Stable	18%
	Kansas City Power & Light Company - Greater MO	Baa2	Stable	22%
	Madison Gas and Electric Company	A1	Stable	30%
	MidAmerican Energy Company	A1	Stable	24%
	Mississippi Power Company	Baa1	Stable	14%
	Nevada Power Company	Baa1	Stable	18%

	Entity Name	LT Rating	Outlook	CFO/Debt (3-Yr Avg) LTM 3Q11-LTM3Q13
	Northern States Power Company (Minnesota)	A2	Stable	25%
	Northern States Power Company (Wisconsin)	(P)A2	Stable	30%
	NorthWestern Corporation	A3	Stable	19%
	Ohio Power Company	Baa1	Stable	32%
	Oklahoma Gas & Electric Company	A1	Stable	27%
	Otter Tail Power Company	A3	Stable	24%
	Pacific Gas & Electric Company	A3	Stable	25%
	PacifiCorp	A3	Stable	23%
	Portland General Electric Company	A3	Stable	25%
	Public Service Co. of North Carolina, Inc.	A3	Stable	25%
	Public Service Company of Colorado	A3	Stable	23%
	Public Service Company of New Hampshire	Baa1	Stable	20%
	Public Service Company of New Mexico	Baa2	Positive	21%
	Public Service Company of Oklahoma	A3	Stable	27%
	Puget Sound Energy, Inc.	Baa1	Stable	21%
	San Diego Gas & Electric Company	A1	Stable	21%
	Sierra Pacific Power Company	Baa1	Stable	16%
	South Carolina Electric & Gas Company	Baa2	Stable	17%
	Southern California Edison Company	A2	Stable	30%
	Southern Indiana Gas & Electric Company	A2	Stable	28%
	Southwestern Electric Power Company	Baa2	Stable	18%
	Southwestern Public Service Company	Baa1	Stable	21%
	Tampa Electric Company	A2	Stable	32%
	Tucson Electric Power Company	Baa1	Stable	19%
	Union Electric Company	(P)Baa1	Stable	22%
	UNS Energy Corporation	Baa2	Stable	19%
	Virginia Electric and Power Company	A2	Stable	27%
	Westar Energy, Inc.	Baa1	Stable	16%
	Wisconsin Electric Power Company	A1	Stable	17%
	Wisconsin Power and Light Company	A1	Stable	31%
	Wisconsin Public Service Corporation	A1	Stable	26%
T&Ds	AEP Texas North Company	Baa1	Stable	22%
	Ameren Illinois Company	(P)Baa1	Stable	26%
	Atlantic City Electric Company	Baa2	Stable	15%
	Baltimore Gas and Electric Company	A3	Stable	19%
	CenterPoint Energy Houston Electric, LLC	A3	Stable	16%
	Central Hudson Gas & Electric Corporation	A2	Stable	29%
	Central Maine Power Company	A3	Stable	27%
	Cleveland Electric Illuminating Company (The)	Baa3	Stable	15%
	Commonwealth Edison Company	Baa1	Stable	21%

	Entity Name	LT Rating	Outlook	CFO/Debt (3-Yr Avg) LTM 3Q11-LTM3Q13
	Connecticut Light and Power Company	Baa1	Stable	13%
	Consolidated Edison Company of New York, Inc.	A2	Stable	23%
	Delmarva Power & Light Company	Baa1	Stable	17%
	Duquesne Light Company	A3	Stable	26%
	Jersey Central Power & Light Company	Baa2	Negative	18%
	New York State Electric and Gas Corporation	A3	Stable	26%
	Niagara Mohawk Power Corporation	A3	Stable	23%
	NSTAR Electric Company	A2	Stable	29%
	Ohio Edison Company	Baa2	Stable	25%
	Oncor Electric Delivery Company LLC	Baa3	Stable	20%
	Orange and Rockland Utilities, Inc.	A3	Stable	21%
	PECO Energy Company	A2	Stable	30%
	Pennsylvania Electric Company	Baa2	Stable	18%
	Pennsylvania Power Company	Baa2	Stable	37%
	Potomac Edison Company (The)	Baa3	Stable	19%
	Potomac Electric Power Company	Baa1	Stable	16%
	Public Service Electric and Gas Company	A2	Stable	25%
	Rochester Gas & Electric Corporation	Baa1	Stable	26%
	Texas-New Mexico Power Company	Baa1	Positive	26%
	Toledo Edison Company	Baa3	Stable	8%
	United Illuminating Company	Baa1	Stable	20%
	West Penn Power Company	Baa2	Stable	25%
	Western Massachusetts Electric Company	A3	Stable	23%
LDCs	Atlanta Gas Light Company	A2	Stable	30%
	Atmos Energy Corporation	A2	Stable	23%
	Berkshire Gas Company	Baa1	Stable	29%
	Connecticut Natural Gas Corporation	A3	Stable	26%
	DTE Gas Company	Aa3	Stable	24%
	Indiana Gas Company, Inc.	A2	Stable	27%
	Laclede Gas Company	(P)A3	Stable	26%
	New Jersey Natural Gas Company	(P)Aa2	Stable	19%
	Northern Illinois Gas Company	A2	Stable	49%
	Northwest Natural Gas Company	(P)A3	Stable	20%
	Piedmont Natural Gas Company, Inc.	A2	Stable	23%
	Questar Gas Company	A2	Stable	25%
	SEMCO Energy, Inc.	Baa1	Stable	15%
	SourceGas LLC	Baa2	Stable	14%
	South Jersey Gas Company	A2	Stable	21%
	Southern California Gas Company	A1	Stable	32%
	Southern Connecticut Gas Company	Baa1	Stable	22%

Entity Name	LT Rating	Outlook	CFO/Debt (3-Yr Avg) LTM 3Q11-LTM3Q13
UGI Utilities, Inc.	A2	Stable	27%
UNS Gas, Inc.	Baa1	Stable	27%
Washington Gas Light Company	A1	Stable	35%
Wisconsin Gas LLC	A1	Stable	28%
Yankee Gas Services Company	Baa1	Stable	18%

Source: Moody's Investors Service

Moody's Related Research

Industry Outlooks:

» US Regulated Utilities: Regulation Provides Stability as Business Model Faces Challenges, July 2013 (156754)

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Criteria | Corporates | Utilities:

Key Credit Factors For The Regulated Utilities Industry

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Key Credit Factors For The Regulated Utilities Industry

***(Editor's Note:** This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," published Nov. 26, 2008, "Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.)*

1. Standard & Poor's Ratings Services is refining and adapting its methodology and assumptions for its Key Credit Factors: Criteria For Regulated Utilities. We are publishing these criteria in conjunction with our corporate criteria (see "Corporate Methodology, published Nov. 19, 2013). This article relates to our criteria article, "Principles Of Credit Ratings," Feb. 16, 2011.

2. This criteria article supersedes "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry," Nov. 26, 2008, "Criteria: Assessing U.S. Utility Regulatory Environments," Nov. 7, 2007, and "Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting," Jan. 27, 2010.

SCOPE OF THE CRITERIA

3. These criteria apply to entities where regulated utilities represent a material part of their business, other than U.S. public power, water, sewer, gas, and electric cooperative utilities that are owned by federal, state, or local governmental bodies or by ratepayers. A regulated utility is defined as a corporation that offers an essential or near-essential infrastructure product, commodity, or service with little or no practical substitute (mainly electricity, water, and gas), a business model that is shielded from competition (naturally, by law, shadow regulation, or by government policies and oversight), and is subject to comprehensive regulation by a regulatory body or implicit oversight of its rates (sometimes referred to as tariffs), service quality, and terms of service. The regulators base the rates that they set on some form of cost recovery, including an economic return on assets, rather than relying on a market price. The regulated operations can range from individual parts of the utility value chain (water, gas, and electricity networks or "grids," electricity generation, retail operations, etc.) to the entire integrated chain, from procurement to sales to the end customer. In some jurisdictions, our view of government support can also affect the final rating outcome, as per our government-related entity criteria (see "General Criteria: Rating Government-Related Entities: Methodology and Assumptions," Dec. 9, 2010).

SUMMARY OF THE CRITERIA

4. Standard & Poor's is updating its criteria for analyzing regulated utilities, applying its corporate criteria. The criteria for evaluating the competitive position of regulated utilities amend and partially supersede the "Competitive Position" section of the corporate criteria when evaluating these entities. The criteria for determining the cash flow leverage

assessment partially supersede the "Cash Flow/Leverage" section of the corporate criteria for the purpose of evaluating regulated utilities. The section on liquidity for regulated utilities partially amends existing criteria. All other sections of the corporate criteria apply to the analysis of regulated utilities.

IMPACT ON OUTSTANDING RATINGS

5. These criteria could affect the issuer credit ratings of about 5% of regulated utilities globally due primarily to the introduction of new financial benchmarks in the corporate criteria. Almost all ratings changes are expected to be no more than one notch, and most are expected to be in an upward direction.

EFFECTIVE DATE AND TRANSITION

6. These criteria are effective immediately on the date of publication.

METHODOLOGY

Part I--Business Risk Analysis

Industry risk

7. Within the framework of Standard & Poor's general criteria for assessing industry risk, we view regulated utilities as a "very low risk" industry (category '1'). We derive this assessment from our view of the segment's low risk ('2') cyclicality and very low risk ('1') competitive risk and growth assessment.

8. In our view, demand for regulated utility services typically exhibits low cyclicality, being a function of such key drivers as employment growth, household formation, and general economic trends. Pricing is non-cyclical, since it is usually based in some form on the cost of providing service.

Cyclicality

9. We assess cyclicality for regulated utilities as low risk ('2'). Utilities typically offer products and services that are essential and not easily replaceable. Based on our analysis of global Compustat data, utilities had an average peak-to-trough (PTT) decline in revenues of about 6% during recessionary periods since 1952. Over the same period, utilities had an average PTT decline in EBITDA margin of about 5% during recessionary periods, with PTT EBITDA margin declines less severe in more recent periods. The PTT drop in profitability that occurred in the most recent recession (2007-2009) was less than the long-term average.

10. With an average drop in revenues of 6% and an average profitability decline of 5%, utilities' cyclicality assessment calibrates to low risk ('2'). We generally consider that the higher the level of profitability cyclicality in an industry, the higher the credit risk of entities operating in that industry. However, the overall effect of cyclicality on an industry's risk profile may be mitigated or exacerbated by an industry's competitive and growth environment.

Competitive risk and growth

11. We view regulated utilities as warranting a very low risk ('1') competitive risk and growth assessment. For competitive risk and growth, we assess four sub-factors as low, medium, or high risk. These sub-factors are:

- Effectiveness of industry barriers to entry;
- Level and trend of industry profit margins;
- Risk of secular change and substitution by products, services, and technologies; and
- Risk in growth trends.

Effectiveness of barriers to entry--low risk

12. Barriers to entry are high. Utilities are normally shielded from direct competition. Utility services are commonly naturally monopolistic (they are not efficiently delivered through competitive channels and often require access to public thoroughfares for distribution), and so regulated utilities are granted an exclusive franchise, license, or concession to serve a specified territory in exchange for accepting an obligation to serve all customers in that area and the regulation of its rates and operations.

Level and trend of industry profit margins--low risk

13. Demand is sometimes and in some places subject to a moderate degree of seasonality, and weather conditions can significantly affect sales levels at times over the short term. However, those factors even out over time, and there is little pressure on margins if a utility can pass higher costs along to customers via higher rates.

Risk of secular change and substitution of products, services, and technologies--low risk

14. Utility products and services are not overly subject to substitution. Where substitution is possible, as in the case of natural gas, consumer behavior is usually stable and there is not a lot of switching to other fuels. Where switching does occur, cost allocation and rate design practices in the regulatory process can often mitigate this risk so that utility profitability is relatively indifferent to the substitutions.

Risk in industry growth trends--low risk

15. As noted above, regulated utilities are not highly cyclical. However, the industry is often well established and, in our view, long-range demographic trends support steady demand for essential utility services over the long term. As a result, we would expect revenue growth to generally match GDP when economic growth is positive.

B. Country risk

16. In assessing "country risk" for a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

C. Competitive position

17. In the corporate criteria, competitive position is assessed as ('1') excellent, ('2') strong, ('3') satisfactory, ('4') fair, ('5') weak, or ('6') vulnerable.

18. The analysis of competitive position includes a review of:

- Competitive advantage,
- Scale, scope, and diversity,
- Operating efficiency, and
- Profitability.

19. In the corporate criteria we assess the strength of each of the first three components. Each component is assessed as either: (1) strong, (2) strong/adequate, (3) adequate, (4) adequate/weak, or (5) weak. After assessing these components, we determine the preliminary competitive position assessment by ascribing a specific weight to each component. The applicable weightings will depend on the company's Competitive Position Group Profile. The group profile for regulated utilities is "National Industries & Utilities," with a weighting of the three components as follows: competitive advantage (60%), scale, scope, and diversity (20%), and operating efficiency (20%). Profitability is assessed by combining two sub-components: level of profitability and the volatility of profitability.

20. "Competitive advantage" cannot be measured with the same sub-factors as competitive firms because utilities are not primarily subject to influence of market forces. Therefore, these criteria supersede the "competitive advantage" section of the corporate criteria. We analyze instead a utility's "regulatory advantage" (section 1 below).

Assessing regulatory advantage

21. The 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.

22. We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. Our view of these four pillars is the foundation of a utility's regulatory support. We then assess the utility's business strategy, in particular its regulatory strategy and its ability to manage the tariff-setting process, to arrive at a final regulatory advantage assessment.

23. When assessing regulatory advantage, we first consider four pillars and sub-factors that we believe are key for a utility to recover all its costs, on time and in full, and earn a return on its capital employed:

24. Regulatory stability:

- Transparency of the key components of the rate setting and how these are assessed
- Predictability that lowers uncertainty for the utility and its stakeholders
- Consistency in the regulatory framework over time

25. Tariff-setting procedures and design:

- Recoverability of all operating and capital costs in full
- Balance of the interests and concerns of all stakeholders affected
- Incentives that are achievable and contained

26. Financial stability:

- Timeliness of cost recovery to avoid cash flow volatility
- Flexibility to allow for recovery of unexpected costs if they arise
- Attractiveness of the framework to attract long-term capital
- Capital support during construction to alleviate funding and cash flow pressure during periods of heavy investments

27. Regulatory independence and insulation:

- Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers
- Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event

28. We have summarized the key characteristics of the assessments for regulatory advantage in table 1.

Table 1

Preliminary Regulatory Advantage Assessment

Qualifier	What it means	Guidance
Strong	The utility has a major regulatory advantage due to one or a combination of factors that support cost recovery and a return on capital combined with lower than average volatility of earnings and cash flows.	The utility operates in a regulatory climate that is transparent, predictable, and consistent from a credit perspective.
	There are strong prospects that the utility can sustain this advantage over the long term.	The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base).
	This should enable the utility to withstand economic downturns and political risks better than other utilities.	The tariff set may include a pass-through mechanism for major expenses such as commodity costs, or a higher return on new assets, effectively shielding the utility from volume and input cost risks.
		Any incentives in the regulatory scheme are contained and symmetrical.
		The tariff set includes mechanisms allowing for a tariff adjustment for the timely recovery of volatile or unexpected operating and capital costs.
		There is a track record of earning a stable, compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.
		There is support of cash flows during construction of large projects, and pre-approval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs.
		The utility operates under a regulatory system that is sufficiently insulated from political intervention to efficiently protect the utility's credit risk profile even during stressful events.
Adequate	The utility has some regulatory advantages and protection, but not to the extent that it leads to a superior business model or durable benefit.	It operates in a regulatory environment that is less transparent, less predictable, and less consistent from a credit perspective.
	The utility has some but not all drivers of well-managed regulatory risk. Certain regulatory factors support the business's long-term stability and viability but could result in periods of below-average levels of profitability and greater profit volatility. However, overall these regulatory drivers are partially offset by the utility's disadvantages or lack of sustainability of other factors.	The utility is exposed to delays or is not, with sufficient certainty, able to recover all of its fixed and variable operating costs, investments. and capital costs (depreciation and a reasonable return on the asset base) within a reasonable time.
		Incentive ratemaking practices are asymmetrical and material, and could detract from credit quality.
		The utility is exposed to the risk that it doesn't recover unexpected or volatile costs in a full or less than timely manner due to lack of flexible reopeners or annual revenue adjustments.
		There is an uneven track record of earning a compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record.

Table 1

Preliminary Regulatory Advantage Assessment (cont.)		
		There is little or no support of cash flows during construction, and investment decisions on large projects (and therefore the risk of subsequent disallowances of capital costs) rest mostly with the utility.
		The utility operates under a regulatory system that is not sufficiently insulated from political intervention and is sometimes subject to overt political influence.
Weak	The utility suffers from a complete breakdown of regulatory protection that places the utility at a significant disadvantage.	The utility operates in an opaque regulatory climate that lacks transparency, predictability, and consistency.
	The utility's regulatory risk is such that the long-term cost recovery and investment return is highly uncertain and materially delayed, leading to volatile or weak cash flows. There is the potential for material stranded assets with no prospect of recovery.	The utility cannot fully and/or timely recover its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base).
		There is a track record of earning minimal or negative rates of return in cash through various economic and political cycles and a projected inability to improve that record sustainably.
		The utility must make significant capital commitments with no solid legal basis for the full recovery of capital costs.
		Ratemaking practices actively harm credit quality.
		The utility is regularly subject to overt political influence.

29. After determining the preliminary regulatory advantage assessment, we then assess the utility's business strategy. Most importantly, this factor addresses the effectiveness of a utility's management of the regulatory risk in the jurisdiction(s) where it operates. In certain jurisdictions, a utility's regulatory strategy and its ability to manage the tariff-setting process effectively so that revenues change with costs can be a compelling regulatory risk factor. A utility's approach and strategies surrounding regulatory matters can create a durable "competitive advantage" that differentiates it from peers, especially if the risk of political intervention is high. The assessment of a utility's business strategy is informed by historical performance and its forward-looking business objectives. We evaluate these objectives in the context of industry dynamics and the regulatory climate in which the utility operates, as evaluated through the factors cited in paragraphs 24-27.

30. We modify the preliminary regulatory advantage assessment to reflect this influence positively or negatively. Where business strategy has limited effect relative to peers, we view the implications as neutral and make no adjustment. A positive assessment improves the preliminary regulatory advantage assessment by one category and indicates that management's business strategy is expected to bolster its regulatory advantage through favorable commission rulings beyond what is typical for a utility in that jurisdiction. Conversely, where management's strategy or businesses decisions result in adverse regulatory outcomes relative to peers, such as failure to achieve typical cost recovery or allowed returns, we adjust the preliminary regulatory advantage assessment one category worse. In extreme cases of poor strategic execution, the preliminary regulatory advantage assessment is adjusted by two categories worse (when possible; see table 2) to reflect management decisions that are likely to result in a significantly adverse regulatory outcome relative to peers.

Table 2

Determining The Final Regulatory Advantage Assessment

	--Strategy modifier--			
Preliminary regulatory advantage score	**Positive**	**Neutral**	**Negative**	**Very negative**
Strong	Strong	Strong	Strong/Adequate	Adequate
Strong/Adequate	Strong	Strong/Adequate	Adequate	Adequate/Weak
Adequate	Strong/Adequate	Adequate	Adequate/Weak	Weak
Adequate/Weak	Adequate	Adequate/Weak	Weak	Weak
Weak	Adequate/Weak	Weak	Weak	Weak

Scale, scope, and diversity

31. We consider the key factors for this component of competitive position to be primarily operational scale and diversity of the geographic, economic, and regulatory foot prints. We focus on a utility's markets, service territories, and diversity and the extent that these attributes can contribute to cash flow stability while dampening the effect of economic and market threats.

32. A utility that warrants a Strong or Strong/Adequate assessment has scale, scope, and diversity that support the stability of its revenues and profits by limiting its vulnerability to most combinations of adverse factors, events, or trends. The utility's significant advantages enable it to withstand economic, regional, competitive, and technological threats better than its peers. It typically is characterized by a combination of the following factors:

- A large and diverse customer base with no meaningful customer concentration risk, where residential and small to medium commercial customers typically provide most operating income.
- The utility's range of service territories and regulatory jurisdictions is better than others in the sector.
- Exposure to multiple regulatory authorities where we assess preliminary regulatory advantage to be at least Adequate. In the case of exposure to a single regulatory regime, the regulatory advantage assessment is either Strong or Strong/Adequate.
- No meaningful exposure to a single or few assets or suppliers that could hurt operations or could not easily be replaced.

33. A utility that warrants a Weak or Weak/Adequate assessment lacks scale, scope, and diversity such that it compromises the stability and sustainability of its revenues and profits. The utility's vulnerability to, or reliance on, various elements of this sub-factor is such that it is less likely than its peers to withstand economic, competitive, or technological threats. It typically is characterized by a combination of the following factors:

- A small customer base, especially if burdened by customer and/or industry concentration combined with little economic diversity and average to below-average economic prospects;
- Exposure to a single service territory and a regulatory authority with a preliminary regulatory advantage assessment of Adequate or Adequate/Weak; or
- Dependence on a single supplier or asset that cannot easily be replaced and which hurts the utility's operations.

34. We generally believe a larger service territory with a diverse customer base and average to above-average economic growth prospects provides a utility with cushion and flexibility in the recovery of operating costs and ongoing investment (including replacement and growth capital spending), as well as lessening the effect of external shocks (i.e.,

extreme local weather) since the incremental effect on each customer declines as the scale increases.

35. We consider residential and small commercial customers as having more stable usage patterns and being less exposed to periodic economic weakness, even after accounting for some weather-driven usage variability. Significant industrial exposure along with a local economy that largely depends on one or few cyclical industries potentially contributes to the cyclicality of a utility's load and financial performance, magnifying the effect of an economic downturn.

36. A utility's cash flow generation and stability can benefit from operating in multiple geographic regions that exhibit average to better than average levels of wealth, employment, and growth that underpin the local economy and support long-term growth. Where operations are in a single geographic region, the risk can be ameliorated if the region is sufficiently large, demonstrates economic diversity, and has at least average demographic characteristics.

37. The detriment of operating in a single large geographic area is subject to the strength of regulatory assessment. Where a utility operates in a single large geographic area and has a strong regulatory assessment, the benefit of diversity can be incremental.

Operating efficiency

38. We consider the key factors for this component of competitive position to be:

- Compliance with the terms of its operating license, including safety, reliability, and environmental standards;
- Cost management; and
- Capital spending: scale, scope, and management.

39. Relative to peers, we analyze how successful a utility management achieves the above factors within the levels allowed by the regulator in a manner that promotes cash flow stability. We consider how management of these factors reduces the prospect of penalties for noncompliance, operating costs being greater than allowed, and capital projects running over budget and time, which could hurt full cost recovery.

40. The relative importance of the above three factors, particularly cost and capital spending management, is determined by the type of regulation under which the utility operates. Utilities operating under robust "cost plus" regimes tend to be more insulated given the high degree of confidence costs will invariably be passed through to customers. Utilities operating under incentive-based regimes are likely to be more sensitive to achieving regulatory standards. This is particularly so in the regulatory regimes that involve active consultation between regulator and utility and market testing as opposed to just handing down an outcome on a more arbitrary basis.

41. In some jurisdictions, the absolute performance standards are less relevant than how the utility performs against the regulator's performance benchmarks. It is this performance that will drive any penalties or incentive payments and can be a determinant of the utilities' credibility on operating and asset-management plans with its regulator.

42. Therefore, we consider that utilities that perform these functions well are more likely to consistently achieve determinations that maximize the likelihood of cost recovery and full inclusion of capital spending in their asset bases. Where regulatory resets are more at the discretion of the utility, effective cost management, including of labor, may allow for more control over the timing and magnitude of rate filings to maximize the chances of a constructive outcome such as full operational and capital cost recovery while protecting against reputational risks.

43. A regulated utility that warrants a Strong or Strong/Adequate assessment for operating efficiency relative to peers generates revenues and profits through minimizing costs, increasing efficiencies, and asset utilization. It typically is characterized by a combination of the following:

- High safety record;
- Service reliability is strong, with a track record of meeting operating performance requirements of stakeholders, including those of regulators. Moreover, the utility's asset profile (including age and technology) is such that we have confidence that it could sustain favorable performance against targets;
- Where applicable, the utility is well-placed to meet current and potential future environmental standards;
- Management maintains very good cost control. Utilities with the highest assessment for operating efficiency have shown an ability to manage both their fixed and variable costs in line with regulatory expectations (including labor and working capital management being in line with regulator's allowed collection cycles); or
- There is a history of a high level of project management execution in capital spending programs, including large one-time projects, almost invariably within regulatory allowances for timing and budget.

44. A regulated utility that warrants an Adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that support profit sustainability combined with average volatility. Its cost structure is similar to its peers. It typically is characterized by a combination of the following factors:

- High safety performance;
- Service reliability is satisfactory with a track record of mostly meeting operating performance requirements of stakeholders, including those of regulators. We have confidence that a favorable performance against targets can be mostly sustained;
- Where applicable, the utility may be challenged to comply with current and future environmental standards that could increase in the medium term;
- Management maintains adequate cost control. Utilities that we assess as having adequate operating efficiency mostly manage their fixed and variable costs in line with regulatory expectations (including labor and working capital management being mostly in line with regulator's allowed collection cycles); or
- There is a history of adequate project management skills in capital spending programs within regulatory allowances for timing and budget.

45. A regulated utility that warrants a weak or weak/adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that fail to support profit sustainability combined with below-average volatility. Its cost structure is worse than its peers. It typically is characterized by a combination of the following:

- Poor safety performance;
- Service reliability has been sporadic or non-existent with a track record of not meeting operating performance requirements of stakeholders, including those of regulators. We do not believe the utility can consistently meet performance targets without additional capital spending;
- Where applicable, the utility is challenged to comply with current environmental standards and is highly vulnerable to more onerous standards;
- Management typically exceeds operating costs authorized by regulators;
- Inconsistent project management skills as evidenced by cost overruns and delays including for maintenance capital spending; or
- The capital spending program is large and complex and falls into the weak or weak/adequate assessment, even if

operating efficiency is generally otherwise considered adequate.

Profitability

46. A utility with above-average profitability would, relative to its peers, generally earn a rate of return at or above what regulators authorize and have minimal exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations. Conversely, a utility with below-average profitability would generally earn rates of return well below the authorized return relative to its peers or have significant exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations.

47. The profitability assessment consists of "level of profitability" and "volatility of profitability."

Level of profitability

48. Key measures of general profitability for regulated utilities commonly include ratios, which we compare both with those of peers and those of companies in other industries to reflect different countries' regulatory frameworks and business environments:

- EBITDA margin,
- Return on capital (ROC), and
- Return on equity (ROE).

49. In many cases, EBITDA as a percentage of sales (i.e., EBITDA margin) is a key indicator of profitability. This is because the book value of capital does not always reflect true earning potential, for example when governments privatize or restructure incumbent state-owned utilities. Regulatory capital values can vary with those of reported capital because regulatory capital values are not inflation-indexed and could be subject to different assumptions concerning depreciation. In general, a country's inflation rate or required rate of return on equity investment is closely linked to a utility company's profitability. We do not adjust our analysis for these factors, because we can make our assessment through a peer comparison.

50. For 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. When setting rates, the regulator ultimately bases its decision on an authorized ROE. However, 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.

51. We will use return on capital when pass-through costs distort profit margins--for instance congestion revenues or collection of third-party revenues. This is also the case when the utility uses accelerated depreciation of assets, which in our view might not be sustainable in the long run.

Volatility of profitability

52. We may observe a clear difference between the volatility of actual profitability and the volatility of underlying regulatory profitability. In these cases, we could use the regulatory accounts as a proxy to judge the stability of earnings.

53. We use actual returns to calculate the standard error of regression for regulated utility issuers (only if there are at least

seven years of historical annual data to ensure meaningful results). If we believe recurring mergers and acquisitions or currency fluctuations affect the results, we may make adjustments.

Part II--Financial Risk Analysis

D. Accounting

54. Our analysis of a company's financial statements begins with a review of the accounting to determine whether the statements accurately measure a company's performance and position relative to its peers and the larger universe of corporate entities. To allow for globally consistent and comparable financial analyses, our rating analysis may include quantitative adjustments to a company's reported results. These adjustments also align a company's reported figures with our view of underlying economic conditions and give us a more accurate portrayal of a company's ongoing business. We discuss adjustments that pertain broadly to all corporate sectors, including this sector, in "Corporate Methodology: Ratios And Adjustments." Accounting characteristics and analytical adjustments unique to this sector are discussed below.

Accounting characteristics

55. Some important accounting practices for utilities include:

- For integrated electric utilities that meet native load obligations in part with third-party power contracts, we use our purchased power methodology to adjust measures for the debt-like obligation such contracts represent (see below).
- Due to distortions in leverage measures from the substantial seasonal working-capital requirements of natural gas distribution utilities, we adjust inventory and debt balances by netting the value of inventory against outstanding short-term borrowings. This adjustment provides an accurate view of the company's balance sheet by reducing seasonal debt balances when we see a very high certainty of near-term cost recovery (see below).
- We deconsolidate securitized debt (and associated revenues and expenses) that has been accorded specialized recovery provisions (see below).
- For water utilities that report under U.K. GAAP, we adjust ratios for infrastructure renewals accounting, which permits water companies to capitalize the maintenance spending on their infrastructure assets (see below). The adjustments aim to make those water companies that report under U.K. GAAP more comparable to those that report under accounting regimes that do not permit infrastructure renewals accounting.

56. In the U.S. and selectively in other regions, utilities employ "regulatory accounting," which permits a rate-regulated company to defer some revenues and expenses to match the timing of the recognition of those items in rates as determined by regulators. A utility subject to regulatory accounting will therefore have assets and liabilities on its books that an unregulated corporation, or even regulated utilities in many other global regions, cannot record. We do not adjust GAAP earnings or balance-sheet figures to remove the effects of regulatory accounting. However, as more countries adopt International Financial Reporting Standards (IFRS), the use of regulatory accounting will become more scarce. IFRS does not currently provide for any recognition of the effects of rate regulation for financial reporting purposes, but it is considering the use of regulatory accounting. We do not anticipate altering our fundamental financial analysis of utilities because of the use or non-use of regulatory accounting. We will continue to analyze the effects of regulatory actions on a utility's financial health.

Purchased power adjustment

57. We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates. (See "Standard & Poor's Methodology For Imputing Debt for U.S. Utilities' Power Purchase Agreements," May 7, 2007, for more background and information on the adjustment.)

58. We calculate the present value (PV) of the future stream of capacity payments under the contracts as reported in the financial statement footnotes or as supplied directly by the company. The discount rate used is the same as the one used in the operating lease adjustment, i.e., 7%. For U.S. companies, notes to the financial statements enumerate capacity payments for the coming five years, and a thereafter period. Company forecasts show the detail underlying the thereafter amount, or we divide the amount reported as thereafter by the average of the capacity payments in the preceding five years to get an approximation of annual payments after year five.

59. We also consider new contracts that will start during the forecast period. The company provides us the information regarding these contracts. If these contracts represent extensions of existing PPAs, they are immediately included in the PV calculation. However, a contract sometimes is executed in anticipation of incremental future needs, so the energy will not flow until some later period and there are no interim payments. In these instances, we incorporate that contract in our projections, starting in the year that energy deliveries begin under the contract. The projected PPA debt is included in projected ratios as a current rating factor, even though it is not included in the current-year ratio calculations.

60. The PV is adjusted to reflect regulatory or legislative cost-recovery mechanisms when present. Where there is no explicit regulatory or legislative recovery of PPA costs, as in most European countries, the PV may be adjusted for other mitigating factors that reduce the risk of the PPAs to the utility, such as a limited economic importance of the PPAs to the utility's overall portfolio.The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor.

61. Risk factors based on regulatory or legislative cost recovery typically range between 0% and 50%, but can be as high as 100%. A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity. These utilities are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties that act as intermediaries between retail customers and electricity suppliers. We employ a 50% risk factor in cases where regulators use base rates for the recovery of the fixed PPA costs. If a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed. In certain jurisdictions, true-up mechanisms are more favorable and frequent than the review of base rates, but still do not amount to pure fuel adjustment clauses. Such mechanisms may be triggered by financial thresholds or passage of prescribed periods of time. In these instances, a risk factor between 25% and 50% is

employed. Specialized, legislatively created cost-recovery mechanisms may lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors. We also exclude short-term PPAs where they serve merely as gap fillers, pending either the construction of new capacity or the execution of long-term PPAs.

62. Where there is no explicit regulatory or legislative recovery of PPA costs, the risk factor is generally 100%. We may use a lower risk factor if mitigating factors reduce the risk of the PPAs on the utility. Mitigating factors include a long position in owned generation capacity relative to the utility's customer supply needs that limits the importance of the PPAs to the utility or the ability to resell power in a highly liquid market at minimal loss. A utility with surplus owned generation capacity would be assigned a risk factor of less than 100%, generally 50% or lower, because we would assess its reliance on PPAs as limited. For fixed capacity payments under PPAs related to renewable power, we use a risk factor of less than 100% if the utility benefits from government subsidies. The risk factor reflects the degree of regulatory recovery through the government subsidy.

63. Given the long-term mandate of electric utilities to meet their customers' demand for electricity, and also to enable comparison of companies with different contract lengths, we may use an evergreening methodology. Evergreen treatment extends the duration of short- and intermediate-term contracts to a common length of about 12 years. To quantify the cost of the extended capacity, we use empirical data regarding the cost of developing new peaking capacity, incorporating regional differences. The cost of new capacity is translated into a dollars-per-kilowatt-year figure using a proxy weighted-average cost of capital and a proxy capital recovery period.

64. Some PPAs are treated as operating leases for accounting purposes--based on the tenor of the PPA or the residual value of the asset on the PPA's expiration. We accord PPA treatment to those obligations, in lieu of lease treatment; rather, the PV of the stream of capacity payments associated with these PPAs is reduced to reflect the applicable risk factor.

65. Long-term transmission contracts can also substitute for new generation, and, accordingly, may fall under our PPA methodology. We sometimes view these types of transmission arrangements as extensions of the power plants to which they are connected or the markets that they serve. Accordingly, we impute debt for the fixed costs associated with such transmission contracts.

66. Adjustment procedures:

- Data requirements:
- Future capacity payments obtained from the financial statement footnotes or from management.
- Discount rate: 7%.
- Analytically determined risk factor.

- Calculations:
- Balance sheet debt is increased by the PV of the stream of capacity payments multiplied by the risk factor.
- Equity is not adjusted because the recharacterization of the PPA implies the creation of an asset, which offsets the debt.
- Property, plant, and equipment and total assets are increased for the implied creation of an asset equivalent to the

debt.

- An implied interest expense for the imputed debt is determined by multiplying the discount rate by the amount of imputed debt (or average PPA imputed debt, if there is fluctuation of the level), and is added to interest expense.
- We impute a depreciation component to PPAs. The depreciation component is determined by multiplying the relevant year's capacity payment by the risk factor and then subtracting the implied PPA-related interest for that year. Accordingly, the impact of PPAs on cash flow measures is tempered.
- The cost amount attributed to depreciation is reclassified as capital spending, thereby increasing operating cash flow and funds from operations (FFO).
- Some PPA contracts refer only to a single, all-in energy price. We identify an implied capacity price within such an all-in energy price, to determine an implied capacity payment associated with the PPA. This implied capacity payment is expressed in dollars per kilowatt-year, multiplied by the number of kilowatts under contract. (In cases that exhibit markedly different capacity factors, such as wind power, the relation of capacity payment to the all-in charge is adjusted accordingly.)
- Operating income before depreciation and amortization (D&A) and EBITDA are increased for the imputed interest expense and imputed depreciation component, the total of which equals the entire amount paid for PPA (subject to the risk factor).
- Operating income after D&A and EBIT are increased for interest expense.

Natural gas inventory adjustment

67. In jurisdictions where a pass-through mechanism is used to recover purchased natural gas costs of gas distribution utilities within one year, we adjust for seasonal changes in short-debt tied to building inventories of natural gas in non-peak periods for later use to meet peak loads in peak months. Such short-term debt is not considered to be part of the utility's permanent capital. Any history of non-trivial disallowances of purchased gas costs would preclude the use of this adjustment. The accounting of natural gas inventories and associated short-term debt used to finance the purchases must be segregated from other trading activities.

68. Adjustment procedures:

- Data requirements:
- Short-term debt amount associated with seasonal purchases of natural gas devoted to meeting peak-load needs of captive utility customers (obtained from the company).

- Calculations:
- Adjustment to debt--we subtract the identified short-term debt from total debt.

Securitized debt adjustment

69. For regulated utilities, we deconsolidate debt (and associated revenues and expenses) that the utility issues as part of a securitization of costs that have been segregated for specialized recovery by the government entity constitutionally authorized to mandate such recovery if the securitization structure contains a number of protective features:

- An irrevocable, non-bypassable charge and an absolute transfer and first-priority security interest in transition property;
- Periodic adjustments ("true-up") of the charge to remediate over- or under-collections compared with the debt service obligation. The true-up ensures collections match debt service over time and do not diverge significantly in the short run; and,
- Reserve accounts to cover any temporary short-term shortfall in collections.

70. Full cost recovery is in most instances mandated by statute. Examples of securitized costs include "stranded costs" (above-market utility costs that are deemed unrecoverable when a transition from regulation to competition occurs) and unusually large restoration costs following a major weather event such as a hurricane. If the defined features are present, the securitization effectively makes all consumers responsible for principal and interest payments, and the utility is simply a pass-through entity for servicing the debt. We therefore remove the debt and related revenues and expenses from our measures. (See "Securitizing Stranded Costs," Jan. 18, 2001, for background information.)

71. Adjustment procedures:

- Data requirements:
- Amount of securitized debt on the utility's balance sheet at period end;
- Interest expense related to securitized debt for the period; and
- Principal payments on securitized debt during the period.

- Calculations:
- Adjustment to debt: We subtract the securitized debt from total debt.
- Adjustment to revenues: We reduce revenue allocated to securitized debt principal and interest. The adjustment is the sum of interest and principal payments made during the year.
- Adjustment to operating income after depreciation and amortization (D&A) and EBIT: We reduce D&A related to the securitized debt, which is assumed to equal the principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.
- Adjustment to interest expense: We remove the interest expense of the securitized debt from total interest expense.

- Operating cash flows:
- We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

Infrastructure renewals expenditure

72. In England and Wales, water utilities can report under either IFRS or U.K. GAAP. Those that report under U.K. GAAP are allowed to adopt infrastructure renewals accounting, which enables the companies to capitalize the maintenance spending on their underground assets, called infrastructure renewals expenditure (IRE). Under IFRS, infrastructure renewals accounting is not permitted and maintenance expenditure is charged to earnings in the year incurred. This difference typically results in lower adjusted operating cash flows for those companies that report maintenance expenditure as an operating cash flow under IFRS, than for those that report it as capital expenditure under U.K. GAAP. We therefore make financial adjustments to amounts reported by water issuers that apply U.K. GAAP, with the aim of making ratios more comparable with those issuers that report under IFRS and U.S. GAAP. For example, we deduct IRE from EBITDA and FFO.

73. IRE does not always consist entirely of maintenance expenditure that would be expensed under IFRS. A portion of IRE can relate to costs that would be eligible for capitalization as they meet the recognition criteria for a new fixed asset set out in International Accounting Standard 16 that addresses property, plant, and equipment. In such cases, we may refine our adjustment to U.K. GAAP companies so that we only deduct from FFO the portion of IRE that would not be capitalized under IFRS. However, the information to make such a refinement would need to be of high quality, reliable, and ideally independently verified by a third party, such as the company's auditor. In the absence of this, we assume

that the entire amount of IRE would have been expensed under IFRS and we accordingly deduct the full expenditure from FFO.

74. Adjustment procedures:

- Data requirements:
- U.K. GAAP accounts typically provide little information on the portion of capital spending that relates to renewals accounting, or the related depreciation, which is referred to as the infrastructure renewals charge. The information we use for our adjustments is, however, found in the regulatory cost accounts submitted annually by the water companies to the Water Services Regulation Authority, which regulates all water companies in England and Wales.

- Calculations:
- EBITDA: Reduced by the value of IRE that was capitalized in the period.
- EBIT: Adjusted for the difference between the adjustment to EBITDA and the reduction in the depreciation expense, depending on the degree to which the actual cash spending in the current year matches the planned spending over the five-year regulatory review period.
- Cash flow from operations and FFO: Reduced by the value of IRE that was capitalized in the period.
- Capital spending: Reduced by the value of infrastructure renewals spending that we reclassify to cash flow from operations.
- Free operating cash flow: No impact, as the reduction in operating cash flows is exactly offset by the reduction in capital spending.

E. Cash flow/leverage analysis

75. In assessing the cash flow adequacy of a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology"). We assess cash flow/leverage on a six-point scale ranging from ('1') minimal to ('6') highly leveraged. These scores are determined by aggregating the assessments of a range of credit ratios, predominantly cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations.

76. The corporate methodology provides benchmark ranges for various cash flow ratios we associate with different cash flow leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

77. If an industry's volatility levels are low, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment are less stringent, although the width of the ratio range is narrower. Conversely, if an industry has standard levels of volatility, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment may be elevated, but with a wider range of values.

78. We apply the "low-volatility" table to regulated utilities that qualify under the corporate criteria and with all of the following characteristics:

- A vast majority of operating cash flows come from regulated operations that are predominantly at the low end of the utility risk spectrum (e.g., a "network," or distribution/transmission business unexposed to commodity risk and with very low operating risk);
- A "strong" regulatory advantage assessment;

- An established track record of normally stable credit measures that is expected to continue;
- A demonstrated long-term track record of low funding costs (credit spread) for long-term debt that is expected to continue; and
- Non-utility activities that are in a separate part of the group (as defined in our group rating methodology) that we consider to have "nonstrategic" group status and are not deemed high risk and/or volatile.

79. We apply the "medial volatility" table to companies that do not qualify under paragraph 78 with:

- A majority of operating cash flows from regulated activities with an "adequate" or better regulatory advantage assessment; or
- About one-third or more of consolidated operating cash flow comes from regulated utility activities with a "strong" regulatory advantage and where the average of its remaining activities have a competitive position assessment of '3' or better.

80. We apply the "standard-volatility" table to companies that do not qualify under paragraph 79 and with either:

- About one-third or less of its operating cash flow comes from regulated utility activities, regardless of its regulatory advantage assessment; or
- A regulatory advantage assessment of "adequate/weak" or "weak."

Part III--Rating Modifiers

F. Diversification/portfolio effect

81. In assessing the diversification/portfolio effect on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

G. Capital structure

82. In assessing the quality of the capital structure of a regulated utility, we use the same methodology as with other corporate issuers (see "Corporate Methodology").

H. Liquidity

83. In assessing a utility's liquidity/short-term factors, our analysis is consistent with the methodology that applies to corporate issuers (See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers," Nov. 19, 2013) except for the standards for "adequate" liquidity set out in paragraph 84 below.

84. The relative certainty of financial performance by utilities operating under relatively predictable regulatory monopoly frameworks make these utilities attractive to investors even in times of economic stress and market turbulence compared to conventional industrials. For this reason, utilities with business risk profiles of at least "satisfactory" meet our definition of "adequate" liquidity based on a slightly lower ratio of sources to uses of funds of 1.1x compared with the standard 1.2x. Also, recognizing the cash flow stability of regulated utilities we allow more discretion when calculating covenant headroom. We consider that utilities have adequate liquidity if they generate positive sources over uses, even if forecast EBITDA declines by 10% (compared with the 15% benchmark for corporate issuers) before covenants are breached.

I. Financial policy

85. In assessing financial policy on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

J. Management and governance

86. In assessing management and governance on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

K. Comparable ratings analysis

87. In assessing the comparable ratings analysis on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology").

Appendix--Frequently Asked Questions

Does Standard & Poor's expect that the business strategy modifier to the preliminary regulatory advantage will be used extensively?

88. Globally, we expect management's influence will be neutral in most jurisdictions. Where the regulatory assessment is "strong," it is less likely that a negative business strategy modifier would be used due to the nature of the regulatory regime that led to the "strong" assessment in the first place. Utilities in "adequate/weak" and "weak" regulatory regimes are challenged to outperform due to the uncertainty of such regulatory regimes. For a positive use of the business strategy modifier, there would need to be a track record of the utility consistently outperforming the parameters laid down under a regulatory regime, and we would need to believe this could be sustained. The business strategy modifier is most likely to be used when the preliminary regulatory advantage assessment is "strong/adequate" because the starting point in the assessment is reasonably supportive, and a utility has shown it manages regulatory risk better or worse than its peers in that regulatory environment and we expect that advantage or disadvantage will persist. An example would be a utility that can consistently earn or exceed its authorized return in a jurisdiction where most other utilities struggle to do so. If a utility is treated differently by a regulator due to perceptions of poor customer service or reliability and the "operating efficiency" component of the competitive position assessment does not fully capture the effect on the business risk profile, a negative business strategy modifier could be used to accurately incorporate it into our analysis. We expect very few utilities will be assigned a "very negative" business strategy modifier.

Does a relatively strong or poor relationship between the utility and its regulator compared with its peers in the same jurisdiction necessarily result in a positive or negative adjustment to the preliminary regulatory advantage assessment?

89. No. The business strategy modifier is used to differentiate a company's regulatory advantage within a jurisdiction where we believe management's business strategy has and will positively or negatively affect regulatory outcomes beyond what is typical for other utilities in that jurisdiction. For instance, in a regulatory jurisdiction where allowed returns are negotiated rather than set by formula, a utility that is consistently authorized higher returns (and is able to earn that return) could warrant a positive adjustment. A management team that cannot negotiate an approved capital spending program to improve its operating performance could be assessed negatively if its performance lags behind peers in the same regulatory jurisdiction.

What is your definition of regulatory jurisdiction?

90. A regulatory jurisdiction is defined as the area over which the regulator has oversight and could include single or multiple subsectors (water, gas, and power). A geographic region may have several regulatory jurisdictions. For example, the Office of Gas and Electricity Markets and the Water Services Regulation Authority in the U.K. are considered separate regulatory jurisdictions. In Ontario, Canada, the Ontario Energy Board represents a single jurisdiction with regulatory oversight for power and gas. Also, in Australia, the Australian Energy Regulator would be considered a single jurisdiction given that it is responsible for both electricity and gas transmission and distribution networks in the entire country, with the exception of Western Australia.

Are there examples of different preliminary regulatory advantage assessments in the same country or jurisdiction?

91. Yes. In Israel we rate a regulated integrated power utility and a regulated gas transmission system operator (TSO). The power utility's relationship with its regulator is extremely poor in our view, which led to significant cash flow volatility in a stress scenario (when terrorists blew up the gas pipeline that was then Israel's main source of natural gas, the utility was unable to negotiate compensation for expensive alternatives in its regulated tariffs). We view the gas TSO's relationship with its regulator as very supportive and stable. Because we already reflected this in very different preliminary regulatory advantage assessments, we did not modify the preliminary assessments because the two regulatory environments in Israel differ and were not the result of the companies' respective business strategies.

How is regulatory advantage assessed for utilities that are a natural monopoly but are not regulated by a regulator or a specific regulatory framework, and do you use the regulatory modifier if they achieve favorable treatment from the government as an owner?

92. The four regulatory pillars remain the same. On regulatory stability we look at the stability of the setup, with more emphasis on the historical track record and our expectations regarding future changes. In tariff-setting procedures and design we look at the utility's ability to fully recover operating costs, investments requirements, and debt-service obligations. In financial stability we look at the degree of flexibility in tariffs to counter volume risk or commodity risk. The flexibility can also relate to the level of indirect competition the utility faces. For example, while Nordic district heating companies operate under a natural monopoly, their tariff flexibility is partly restricted by customers' option to change to a different heating source if tariffs are significantly increased. Regulatory independence and insulation is mainly based on the perceived risk of political intervention to change the setup that could affect the utility's credit profile. Although political intervention tends to be mostly negative, in certain cases political ties due to state ownership might positively influence tariff determination. We believe that the four pillars effectively capture the benefits from the close relationship between the utility and the state as an owner; therefore, we do not foresee the use of the regulatory modifier.

In table 1, when describing a "strong" regulatory advantage assessment, you mention that there is support of cash flows during construction of large projects, and preapproval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs. Would this preclude a "strong" regulatory advantage assessment in jurisdictions where those practices are absent?

93. No. The table is guidance as to what we would typically expect from a regulatory framework that we would assess as "strong." We would expect some frameworks with no capital support during construction to receive a "strong" regulatory advantage assessment if in aggregate the other factors we analyze support that conclusion.

RELATED CRITERIA AND RESEARCH

- Corporate Methodology, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions, Nov. 19, 2013
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Nov. 19, 2013
- Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities and Insurers, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, Dec. 9, 2010

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

INDUSTRY TIMELINESS: 87 (of 97)

All of the major utilities in the eastern region of the United States are reviewed in this Edition. Those serving the central region will be found in Edition five. All of the western companies are covered in Edition 11.

State electric utility regulators in the eastern region are taking an active role in stimulating competition in their jurisdictions. Our report discusses some of their divergent views.

Some Regulatory Views On Competition

A year and a half ago, the California regulators declared that the state's electricity prices were too high and that a major restructuring of utility operations was necessary to bring them down to reasonable levels. It wasn't long before various state commissions in the East recognized that they, too, must take a hand in bringing down rates.

In New York, for example, where *Long Island Lighting (LILCO)* and *Consolidated Edison (CEC)* have the unenviable distinction of charging the highest rates in the nation, Governor Pataki is under pressure to propose a rate-reduction plan. Three months ago, the Long Island Power Authority (LIPA) offered to buy *LILCO* for $9.2 billion and reduce the utility's rates by 20% in 3 to 5 years. But the Governor opposed the buyout, appointed a new LIPA chairman, and indicated he would do what was best for the people of Long Island. His proposal is expected to include tax-exempt financing of *LILCO's* $4.6 billion of long-term debt and a possible sale of the utility's gas operations and its power plants. Much of the burden would be borne by the Federal Government, and to a lesser extent by the state, neither of which would collect taxes on interest income. The state has no immediate plans to lower rates for *CEC*. A reduction might have to wait for a rollback in the gross receipts tax on electric bills, but the state's budget deficit will likely delay action here. Meanwhile, the Public Service Commission is examining proposals to stimulate competition without jeopardizing the financial integrity of the state's utilities. On the issue of stranded investment, it stated that utilities should have a reasonable opportunity to recover expenditures made pursuant to their legal obligations. But that leaves open the question of who will reimburse the utility for its loss of business. Political pressures might force shareholders to absorb some of the burden.

In New Hampshire, the commission issued a controversial decision that utilities in the state do not necessarily have exclusive franchises. It denied motions for reconsideration by *Northeast Utilities* and *New England Electric*. The utilities had contended that the exclusive franchise principle was well established and that the commission's policy was illegal. They have appealed the ruling to the courts. Meanwhile, Governor Merrill signed a bill authorizing retail wheeling (the use of one utility's transmission lines by another for the sale of power to an end user). The commission expects to initiate a retail wheeling pilot program by next April. This would make New Hampshire one of the first states to meet the issue head on.

By contrast, the North Carolina and Maryland regulators have rejected retail wheeling. The North Carolina commission stated that its territorial assignment law divides the state into areas to be served by specific utilities and that any change would be prohibited by statute. The Maryland regulators noted that their industrial rates were sufficiently low, so there was no immediate need for a quick fix at this time.

In Rhode Island, an understanding was reached between the state's utilities and business and consumer groups on general guidelines for an open energy market. The agreement called for a spot market for the purchase and sale of power, retail wheeling, and the recovery of stranded investments by charges to customers rather than by wheeling fees. The agreement has such broad support that it could lay the groundwork for similar restructuring in other New England states.

Numerous state commissions in the eastern region have solicited input on competition from interested parties. Some have established general guidelines. But conditions vary from state to state, as evidenced by the divergence of views promulgated to date. It is still too early to predict what adjustments will be made in the long-standing regulatory compact nationwide and how individual utilities will be affected by the inevitable surfacing of competition.

Investment Advice

The industry is undergoing a period of radical change. There will be some winners and some losers in the new environment. Before making a utility purchase, investors would do well to examine a company's finances and its industrial rates relative to those of its neighbors. For now, the group as a whole is not timely.

Arthur H. Medalie

Composite Statistics: Electric Utility Industry

1991	1992	1993	1994	1995	1996		98-00
174.4	178.5	186.2	195.1	200	203	Revenues ($bill)	220
18.4	18.6	19.9	19.8	21.5	21.5	Net Profit ($bill)	24.0
33.8%	34.5%	35.1%	36.0%	34.5%	34.5%	Income Tax Rate	35.0%
8.4%	7.0%	7.0%	4.4%	4.0%	4.0%	AFUDC % to Net Profit	4.0%
50.1%	50.1%	49.7%	48.9%	47.5%	48.0%	Long-Term Debt Ratio	46.0%
42.9%	42.9%	43.6%	44.6%	45.5%	46.0%	Common Equity Ratio	47.5%
338.9	352.8	364.0	369.0	376	387	Total Capital ($bill)	405
363.2	376.0	395.7	403.9	410	404	Net Plant ($bill)	430
7.7%	7.4%	7.4%	7.3%	7.6%	7.5%	% Earned Total Cap'l	7.7%
10.9%	10.8%	10.9%	10.5%	11.0%	11.0%	% Earned Net Worth	11.1%
11.4%	11.1%	11.5%	11.1%	11.5%	11.5%	% Earned Comm Equity	11.6%
2.4%	2.0%	2.5%	2.2%	3.0%	2.9%	% Retained to Comm Eq	3.0%
81%	83%	80%	82%	77%	77%	% All Div'ds to Net Prof	75%
12.0	13.5	14.2	12.0	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	11.0
.77	.82	.84	.79			Relative P/E Ratio	.85
6.6%	6.1%	5.5%	6.6%			Avg Ann'l Div'd Yield	6.6%

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	1992	1993	1994
% Change Sales (kwh)	+.2	+2.5	+2.1
Average Residential Use (kwh)	9484	9739	9825
Avg. Resid. Revs. per kwh (¢)	8.17	8.27	8.45
Capacity at Peak (mw)	695436	694250	702985
Peak Load, Summer (mw)	548253	575356	585320
Annual Load Factor (%)	61.4	61.0	61.2
% Change Customers (yr.-end)	+1.1	+.9	+1.1
Fixed Charge Coverage (%)	212	230	240

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

All the major utilities in the eastern region of the U.S. are reviewed in this Issue. Those serving the central region will be found in Issue 5. All of the western providers are covered in Issue 11.

Stocks in the Electric Utility Industry have significantly underperformed the broader market averages thus far in 2012. Year-to-date, the Value Line Utility Index has declined 0.7%, while the Value Line Geometric Index has risen 10%. In our view, it appears the investment community is becoming increasingly confident that economic trends will continue to improve in the coming quarters. As a result, it comes as little surprise to see investors becoming a bit more venturesome with their equity picks, exploring more volatile sectors with the potential for higher returns. Due to their relative stability and strong dividend payouts, Electric Utility stocks tend to outperform the broader market averages during times of an economic slowdown. Conversely, they tend to underperform during periods of economic expansion.

In the following report we touch on a breakthrough in the nuclear sector, merger and acquistions within the industry, and several attractive high-yield plays for investors seeking income.

NRC Approves First Nuclear Plant Since 1978

On February 9th, the Nuclear Regulatory Commission approved Atlanta-based ***Southern Co.'s*** request to build two nuclear reactors at its site in Vogtle, GA. This is the first licence to be granted by federal regulators in over three decades. We consider this to be a major test of whether the industry can construct a nuclear facility without the delays and cost overruns that hampered earlier attempts. Assuming no setbacks, the reactors are scheduled to be up and running by 2016-2017.

Mergers and Acquisitions

Duke Energy's $16 billion buyout of rival ***Progress Energy*** is still pending. With both companies gaining shareholder approval last August, the actual closing date will ultimately be determined by the timing of approvals by the Federal Energy Regulatory Commission (FERC) and the state commissions in North Carolina and South Carolina. The state commissions indicated they will make their rulings after FERC's decision, which is currently pegged for mid- to late May.

INDUSTRY TIMELINESS: 46 (of 98)

Northeast Utilities $4.7 billion acquisition of ***NSTAR*** will now require regulatory approval in Connecticut. Initially, state regulators ruled they did not have jurisdiction over the deal, but after numerous complaints from various parties, they reversed their position. The Connecticut commission is scheduled to issue their decision by April 2nd. On a positive note, the companies have reached a settlement in Massachusetts. The agreement calls for the utilities to give a one-time, $21 million rate credit for their respective customers. Base distribution tariffs would be frozen until 2016 and there would be various commitments to renewable energy. The companies requested Massachusetts regulators approve the deal by April 4th.

Exelon Corp's $7.3 billion bid to acquire ***Constellation Energy*** has made progress in recent months. After earlier setbacks, the combination reached a settlement with most key intervenors in Maryland. A ruling is expected from the state commission shortly after this report went to press. The transaction still requires approval from the Nuclear Regulatory Commission and the Federal Regulatory Commission. We will provide further insight when more information is available.

Dividends

Stocks in the Electric Utility industry are yielding 4.2%, on average, nearly two full percentage points above the ***Value Line Investment Survey*** median. Income-oriented investors should have little trouble finding attractive options within the group. Top-yielders in Issue 1 include, ***Pepco Holdings*** (5.5%), ***FirstEnergy*** (5.1%), ***PPL Corp.*** (5.0%), and ***UIL Holdings*** (4.9%).

Conclusion

Last year's outperformance of Electric Utility Stocks largely dampened their appeal entering 2012. Despite the industry's recent slump relative to the broader market, many of these issues are still trading within their 3- to 5-year Target Price Ranges, indicating valuations may be a bit high. Investors with a long-term mindset may find better options elsewhere.

Michael Ratty

Composite Statistics: Electric Utility Industry

2008	2009	2010	2011	2012	2013		15-17
363.6	321.4	329.2	*320*	*325*	*335*	Revenues ($bill)	*385*
27.7	27.7	30.1	*28.0*	*30.0*	*31.0*	Net Profit ($bill)	*37.0*
33.5%	32.2%	34.2%	*33.5%*	*34.5%*	*34.5%*	Income Tax Rate	*34.5%*
7.8%	9.2%	8.5%	*7.0%*	*7.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
53.6%	52.4%	52.2%	*51.0%*	*50.5%*	*50.5%*	Long-Term Debt Ratio	*50.0%*
45.4%	46.6%	47.0%	*48.5%*	*49.0%*	*49.0%*	Common Equity Ratio	*49.5%*
514.0	554.1	587.5	*575*	*605*	*630*	Total Capital ($bill)	*720*
554.4	594.5	640.1	*635*	*675*	*705*	Net Plant ($bill)	*800*
6.9%	6.5%	6.6%	*6.0%*	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
11.6%	10.5%	10.7%	*10.0%*	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
11.8%	10.6%	10.8%	*10.0%*	*10.0%*	*10.0%*	Return on Com Equity	*10.5%*
4.9%	4.2%	4.5%	*4.0%*	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
58%	61%	59%	*62%*	*61%*	*61%*	All Div'ds to Net Prof	*59%*
15.4	12.5	12.9		*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*13.5*
.93	.83	.82			*estimates*	Relative P/E Ratio	*.90*
3.8%	4.8%	4.5%				Avg Ann'l Div'd Yield	*4.3%*

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2008	2009	2010
% Change Retail Sales (kwh)	-1.1	-5.4	+3.6
Average Indust. Use (mwh)	1529	1446	1530
Avg. Indust. Revs. per kwh (¢)	6.66	6.46	6.56
Regulated Cap. at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+.1	-.2	+1.6
Fixed Charge Coverage (%)	311	280	305

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

NEW REGULATORY FINANCE

Roger A. Morin, PhD

2006
PUBLIC UTILITIES REPORTS, INC.
Vienna, Virginia

The average growth rate estimate from all the analysts that follow the company measures the consensus expectation of the investment community for that company. In most cases, it is necessary to use earnings forecasts rather than dividend forecasts due to the extreme scarcity of dividend forecasts compared to the widespread availability of earnings forecasts. Given the paucity and variability of dividend forecasts, using the latter would produce unreliable DCF results. In any event, the use of the DCF model prospectively assumes constant growth in both earnings and dividends. Moreover, as discussed below, there is an abundance of empirical research that shows the validity and superiority of earnings forecasts relative to historical estimates when estimating the cost of capital.

The uniformity of growth projections is a test of whether they are typical of the market as a whole. If, for example, 10 out of 15 analysts forecast growth in the 7%–9% range, the probability is high that their analysis reflects a degree of consensus in the market as a whole. As a side note, the lack of uniformity in growth projections is a reasonable indicator of higher risk. Chapter 3 alluded to divergence of opinion amongst analysts as a valid risk indicator.

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. The accuracy of these forecasts in the sense of whether they turn out to be correct is not at issue here, as long as they reflect widely held expectations. As long as the forecasts are typical and/or influential in that they are consistent with current stock price levels, they are relevant. The use of analysts' forecasts in the DCF model is sometimes denounced on the grounds that it is difficult to forecast earnings and dividends for only one year, let alone for longer time periods. This objection is unfounded, however, because it is present investor expectations that are being priced; it is the consensus forecast that is embedded in price and therefore in required return, and not the future as it will turn out to be.

Empirical Literature on Earnings Forecasts

Published studies in the academic literature demonstrate that growth forecasts made by security analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth. These studies show that investors rely on analysts' forecasts to a greater extent than on historic data only.

Academic research confirms the superiority of analysts' earnings forecasts over univariate time-series forecasts that rely on history. This latter category

THE COST OF CAPITAL –

A PRACTITIONER'S GUIDE

BY

DAVID C. PARCELL

PREPARED FOR THE SOCIETY OF UTILITY AND REGULATORY FINANCIAL ANALYSTS

1997 EDITION

Author's Note: This manual has been prepared as an educational reference on cost of capital concepts. Its purpose is to describe a broad array of cost of capital models and techniques. No cost of equity model or other concept is recommended or emphasized, nor is any procedure for employing any model recommended. Furthermore, no opinions or preferences are expressed by either the author or the Society of Utility And Regulatory Financial Analysts.

"incorporates all information relating to equity valuation contained in alternative proxies"; however, their studies indicate that forecasts do not contain all relevant information and thus should not be relied upon exclusively. Conroy and Harris (1987) found that analysts' forecasts were better predictors than historic growth over the very short term, but the advantage declined steadily over time. They conclude that combinations of analysts' forecasts and historic growth provide the best forecasting results. Avera and Fairchild (1982) and Newbolt, Zumwalt, and Kannan (1987) reached similar conclusions.

3. **Whose Projections Are Best?**

Finally, a number of studies have commented on the relative accuracy of various analysts' forecasts. Brown and Rozeff (1978) found that Value Line was superior to other forecasts. Chatfield, Hein and Moyer (1990, 438) found, further "Value Line to be more accurate than alternative forecasting methods" and that "investors place the greatest weight on the forecasts provided by Value Line". Finally, Collins and Hopwood (1980) concluded that Value Line predictions are more accurate than competing models as they produce fewer and smaller extreme errors. In contrast, Avera and Fairchild (1982) contend that Value Line forecasts are not an acceptable surrogate for the growth component in the DCF model.

IHS GLOBAL INSIGHT

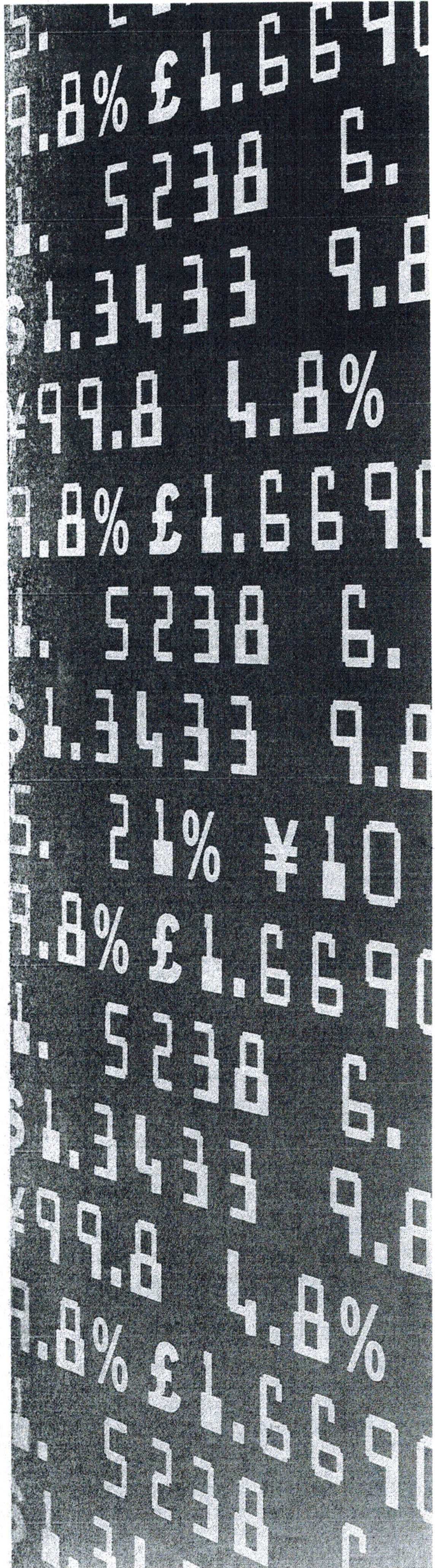
The U.S. Economy: The 30-Year Focus (Third-Quarter 2014)

	(c) Aaa Corp.	(c) Seasoned Baa Corp.	(c) Aa Utility	(c) 3-Mo. T-Bill	(c) Bond Equiv. Yield 3-Mo. T-Bill	(c) 10-Year T-Note	(c) 30-Year T-Bond
2013	4.24	5.10	4.24	0.06	0.06	2.35	3.45
2014	4.18	4.85	4.20	0.03	0.03	2.57	3.37
2015	4.62	5.58	4.96	0.45	0.45	3.13	3.83
2016	5.16	6.22	5.80	1.59	1.62	3.64	4.19
2017	5.71	6.85	6.49	3.20	3.27	4.21	4.54
2018	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2019	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2020	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2021	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2022	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2023	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2024	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2025	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2026	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2027	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2028	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2029	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2030	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2031	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2032	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2033	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2034	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2035	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2036	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2037	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2038	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2039	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2040	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2041	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2042	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2043	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2044	5.84	6.99	6.62	3.51	3.59	4.36	4.58
2045							
2046							

(a) Table 1.
(b) Table 36.
(c) Table 34.

Attachment in Excel

The attachment(s) provided in separate file(s) in Excel format.



BLUE CHIP FINANCIAL FORECASTS

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them.

Vol. 33, No. 12
December 1, 2014

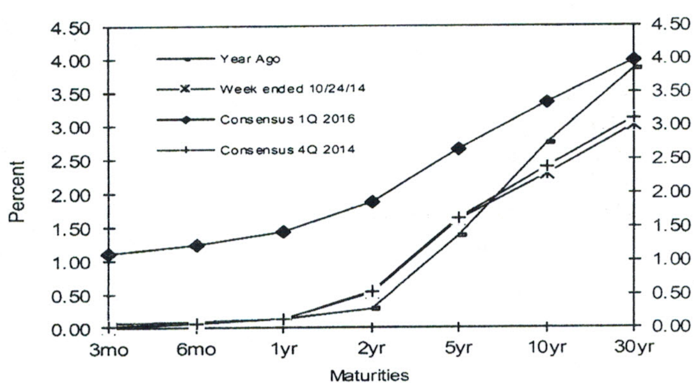
Wolters Kluwer
Law & Business

Consensus Forecasts Of U.S. Interest Rates And Key Assumptions[1]

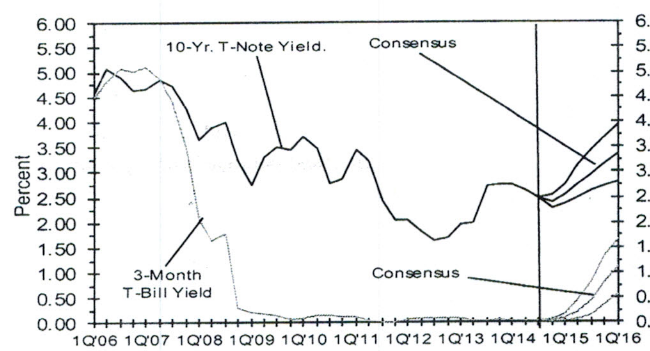
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Q	4Q	1Q	2Q	3Q	4Q	1Q
Interest Rates	Nov. 28	Nov. 21	Nov. 14	Nov. 7	Oct.	Sep.	Aug.	3Q 2014	2014	2015	2015	2015	2015	2016
Federal Funds Rate	0.10	0.10	0.09	0.08	0.09	0.09	0.09	0.09	0.1	0.1	0.2	0.5	0.8	1.1
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.3	3.3	3.3	3.5	3.8	4.1
LIBOR, 3-mo.	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.3	0.3	0.4	0.7	1.0	1.4
Commercial Paper, 1-mo.	0.07	0.07	0.07	0.07	0.06	0.06	0.08	0.07	0.1	0.1	0.3	0.5	0.9	1.2
Treasury bill, 3-mo.	0.02	0.02	0.02	0.03	0.02	0.02	0.03	0.03	0.0	0.1	0.2	0.5	0.8	1.1
Treasury bill, 6-mo.	0.07	0.07	0.07	0.06	0.05	0.04	0.05	0.05	0.1	0.1	0.3	0.6	0.9	1.2
Treasury bill, 1 yr.	0.14	0.14	0.14	0.12	0.10	0.11	0.11	0.11	0.1	0.3	0.5	0.8	1.1	1.4
Treasury note, 2 yr.	0.53	0.53	0.54	0.52	0.45	0.57	0.47	0.52	0.5	0.7	1.0	1.3	1.6	1.9
Treasury note, 5 yr.	1.61	1.64	1.64	1.63	1.55	1.77	1.63	1.70	1.6	1.8	2.0	2.2	2.4	2.7
Treasury note, 10 yr.	2.29	2.33	2.36	2.36	2.30	2.53	2.42	2.50	2.4	2.5	2.7	3.0	3.2	3.3
Treasury note, 30 yr.	3.00	3.05	3.08	3.06	3.04	3.26	3.20	3.26	3.1	3.3	3.4	3.6	3.8	4.0
Corporate Aaa bond	3.93	3.96	3.95	3.90	3.92	4.11	4.08	4.12	4.0	4.2	4.4	4.6	4.7	4.9
Corporate Baa bond	4.80	4.84	4.80	4.76	4.69	4.80	4.69	4.72	4.8	5.0	5.2	5.4	5.5	5.7
State & Local bonds	n.a.	3.93	3.98	3.98	3.96	4.13	4.23	4.23	4.0	4.1	4.3	4.5	4.6	4.8
Home mortgage rate	3.97	3.99	4.01	4.02	4.04	4.16	4.12	4.14	4.1	4.2	4.4	4.6	4.8	5.0
	History								Consensus Forecasts-Quarterly					
	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q
Key Assumptions	2012	2013	2013	2013	2013	2014	2014	2014	2014	2015	2015	2015	2015	2016
Major Currency Index	73.2	74.7	76.4	76.7	76.0	77.1	76.6	77.8	82.1	82.9	83.3	83.6	83.7	83.5
Real GDP	0.1	2.7	1.8	4.5	3.5	-2.1	4.6	3.9	2.7	2.9	2.9	3.0	3.0	2.8
GDP Price Index	1.3	1.3	1.2	1.7	1.5	1.3	2.1	1.4	1.4	1.7	1.9	1.9	2.0	2.0
Consumer Price Index	2.4	1.2	0.4	2.2	1.1	1.9	3.0	1.1	0.6	1.7	2.1	2.2	2.2	2.2

Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data for interest rates except LIBOR is from Federal Reserve Release (FRSR) H.15. LIBOR quotes available from *The Wall Street Journal*. Interest rate definitions are same as those in FRSR H.15. Treasury yields are reported on a constant maturity basis. Historical data for Fed's Major Currency Index is from FRSR H.10 and G.5. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).

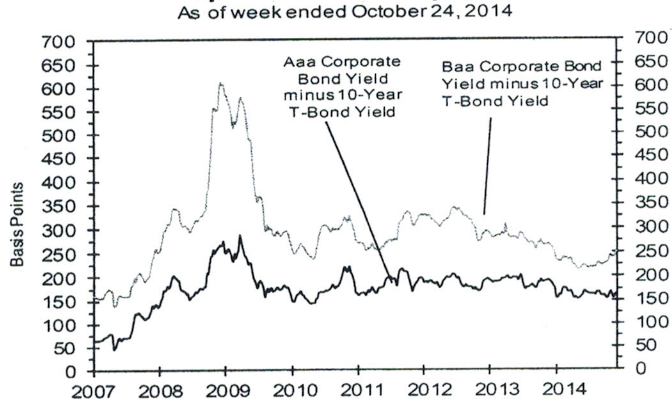
U.S. Treasury Yield Curve
Week ended November 28, 2014 and Year Ago vs. 4Q 2014 and 1Q 2016 Consensus Forecasts



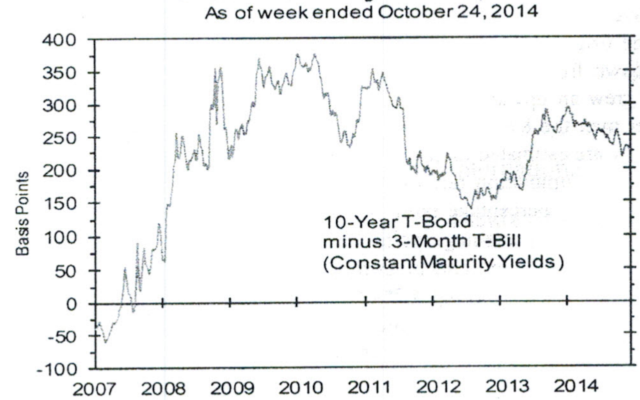
U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield
(Quarterly Average) Forecast



Corporate Bond Spreads
As of week ended October 24, 2014



U.S. Treasury Yield Curve
As of week ended October 24, 2014



Long-Range Estimates:

The table below contains results of our semi-annual long-range CONSENSUS survey. There are also Top 10 and bottom 10 averages for each variable. Shown are estimates for the years 2016 through 2020 and averages for the five-year periods 2016-2020 and 2020-2025. Apply these projections cautiously. Few economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year					Five-Year Averages	
Interest Rates		**2016**	**2017**	**2018**	**2019**	**2020**	**2016-2020**	**2021-2025**
1. Federal Funds Rate	**CONSENSUS**	**1.8**	**2.9**	**3.6**	**3.7**	**3.7**	**3.1**	**3.6**
	Top 10 Average	2.4	3.7	4.2	4.2	4.2	3.7	4.1
	Bottom 10 Average	1.2	2.3	2.9	3.0	3.0	2.5	2.9
2. Prime Rate	**CONSENSUS**	**4.7**	**5.8**	**6.5**	**6.6**	**6.6**	**6.0**	**6.5**
	Top 10 Average	5.4	6.6	7.1	7.2	7.2	6.7	7.1
	Bottom 10 Average	4.2	5.2	5.8	5.9	5.8	5.4	5.6
3. LIBOR, 3-Mo.	**CONSENSUS**	**2.1**	**3.2**	**3.7**	**3.9**	**3.9**	**3.3**	**3.8**
	Top 10 Average	2.7	3.9	4.3	4.4	4.4	3.9	4.3
	Bottom 10 Average	1.5	2.5	3.1	3.2	3.3	2.7	3.3
4. Commercial Paper, 1-Mo.	**CONSENSUS**	**1.9**	**3.0**	**3.5**	**3.7**	**3.7**	**3.1**	**3.7**
	Top 10 Average	2.4	3.5	4.0	4.2	4.2	3.6	4.2
	Bottom 10 Average	1.5	2.5	3.0	3.1	3.2	2.7	3.2
5. Treasury Bill Yield, 3-Mo.	**CONSENSUS**	**1.8**	**2.9**	**3.4**	**3.6**	**3.6**	**3.0**	**3.5**
	Top 10 Average	2.4	3.6	4.0	4.2	4.1	3.7	4.1
	Bottom 10 Average	1.3	2.2	2.9	2.9	2.9	2.4	2.7
6. Treasury Bill Yield, 6-Mo.	**CONSENSUS**	**2.0**	**3.0**	**3.6**	**3.7**	**4.7**	**3.4**	**3.6**
	Top 10 Average	2.5	3.8	4.2	4.4	7.4	4.4	4.2
	Bottom 10 Average	1.5	2.4	3.0	3.1	3.1	2.6	2.8
7. Treasury Bill Yield, 1-Yr.	**CONSENSUS**	**2.1**	**3.2**	**3.7**	**3.8**	**3.8**	**3.3**	**3.7**
	Top 10 Average	2.8	3.9	4.4	4.5	4.4	4.0	4.3
	Bottom 10 Average	1.6	2.5	3.1	3.1	3.2	2.7	2.9
8. Treasury Note Yield, 2-Yr.	**CONSENSUS**	**2.5**	**3.4**	**3.9**	**4.0**	**4.0**	**3.6**	**4.0**
	Top 10 Average	3.3	4.1	4.5	4.7	4.6	4.2	4.5
	Bottom 10 Average	1.9	2.8	3.3	3.3	3.3	2.9	3.2
10. Treasury Note Yield, 5-Yr.	**CONSENSUS**	**3.1**	**3.8**	**4.2**	**4.3**	**4.3**	**4.0**	**4.3**
	Top 10 Average	3.8	4.5	4.9	5.1	5.1	4.7	4.9
	Bottom 10 Average	2.6	3.2	3.6	3.5	3.6	3.3	3.6
11. Treasury Note Yield, 10-Yr.	**CONSENSUS**	**3.7**	**4.3**	**4.6**	**4.7**	**4.7**	**4.4**	**4.6**
	Top 10 Average	4.4	5.0	5.4	5.6	5.6	5.2	5.4
	Bottom 10 Average	3.2	3.5	3.8	3.8	3.9	3.7	3.9
12. Treasury Bond Yield, 30-Yr.	**CONSENSUS**	**4.3**	**4.8**	**5.0**	**5.1**	**5.2**	**4.9**	**5.1**
	Top 10 Average	5.0	5.6	5.9	6.2	6.2	5.8	6.0
	Bottom 10 Average	3.7	4.0	4.2	4.2	4.3	4.1	4.3
13. Corporate Aaa Bond Yield	**CONSENSUS**	**5.1**	**5.6**	**6.0**	**6.1**	**6.1**	**5.8**	**6.1**
	Top 10 Average	5.8	6.4	6.8	7.0	7.0	6.6	6.8
	Bottom 10 Average	4.5	4.8	5.1	5.1	5.2	5.0	5.4
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.5**	**6.8**	**6.9**	**7.0**	**6.6**	**7.0**
	Top 10 Average	6.7	7.3	7.7	7.9	7.9	7.5	7.7
	Bottom 10 Average	5.4	5.6	5.9	5.9	6.0	5.8	6.2
14. State & Local Bonds Yield	**CONSENSUS**	**4.9**	**5.2**	**5.4**	**5.4**	**5.4**	**5.2**	**5.3**
	Top 10 Average	5.5	5.7	6.0	6.1	6.1	5.9	6.0
	Bottom 10 Average	4.3	4.6	4.7	4.7	4.7	4.6	4.7
15. Home Mortgage Rate	**CONSENSUS**	**5.2**	**5.8**	**6.2**	**6.3**	**6.3**	**6.0**	**6.2**
	Top 10 Average	5.9	6.5	7.1	7.2	7.2	6.8	7.0
	Bottom 10 Average	4.6	5.1	5.5	5.5	5.5	5.2	5.3
A. FRB - Major Currency Index	**CONSENSUS**	**83.6**	**83.3**	**82.7**	**82.4**	**82.1**	**82.8**	**82.0**
	Top 10 Average	86.7	86.7	86.6	86.5	86.6	86.6	86.3
	Bottom 10 Average	80.3	79.8	78.5	77.9	77.3	78.7	77.4

		Year-Over-Year, % Change					Five-Year Averages	
		2016	**2017**	**2018**	**2019**	**2020**	**2016-2020**	**2021-2025**
B. Real GDP	**CONSENSUS**	**2.8**	**2.8**	**2.6**	**2.4**	**2.4**	**2.6**	**2.3**
	Top 10 Average	3.2	3.1	2.9	2.8	2.7	2.9	2.6
	Bottom 10 Average	2.6	2.4	2.3	1.8	2.0	2.2	2.0
C. GDP Chained Price Index	**CONSENSUS**	**2.0**	**2.2**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.3	2.7	2.6	2.5	2.4	2.5	2.5
	Bottom 10 Average	1.7	1.8	1.8	1.8	1.8	1.8	1.8
D. Consumer Price Index	**CONSENSUS**	**2.3**	**2.5**	**2.4**	**2.3**	**2.3**	**2.4**	**2.3**
	Top 10 Average	2.7	3.1	3.0	2.8	2.7	2.8	2.7
	Bottom 10 Average	2.0	2.0	2.0	1.9	1.9	1.9	1.9

THE COST OF CAPITAL TO A PUBLIC UTILITY

Myron J. Gordon

1974
MSU Public Utilities Studies

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its leverage rate. It can be shown that when $x = \rho$ the share price is independent of the firm's leverage rate. Hence, the cost of debt capital remains equal to ρ when retention is present.

2.8 Continuous New Equity Financing

In addition to or as an alternative to expanding through the periodic retention of earnings, a utility can expand through the sale of stock.[7] Consideration of the sale of stock as a source of funds requires the introduction of the following variables not listed previously.

W_t = total common equity at end of period t;
W_t^* = total common equity at end of t that accrues to shareholders at $t = 0$;
s = funds raised from the sale of stock as a fraction of existing common equity;
Q_t = funds raised from sale of stock during t; and
v = fraction of Q_t that accrues to shareholders at the start of t.

Let a utility's total common equity at $t = 0$ be $W_0 = NE_0$, and let the expected rate of growth in the common equity due to the sale of stock be s. The common equity one period later will be

$$W_1 = W_0 + bNY_1 + sW_0. \tag{2.8.1}$$

Since $NY_1 = rW_0$,

$$W_1 = W_0 + brW_0 + sW_0 = W_0[1 + br + s], \tag{2.8.2}$$

and

$$W_n = W_0[1 + br + s]^n. \tag{2.8.3}$$

In each period the total equity is raised by the fraction br due to retention and by s due to the sale of additional shares.

At the end of $t = n$ the total common equity will include the equity of the shareholders at $t = 0$ and the equity arising from

[7] This section is based on chapter 9 of M. J. Gordon [15].

the sale of shares from $t = 0$ through $t = n$. What we are interested in, however, is the expected equity and the dividend at $t = n$ on a share outstanding at $t = 0$. Let $Q_n = sW_{n-1}$ be the funds raised from the sale of stock during n, and let v be the fraction of the funds provided during n that accrues to the shareholders at the start of n. The meaning and derivation of v will be developed in the course of what follows.

Let W_n^* be the portion of the total common equity at the end of $t = n$ that belongs to the share outstanding at $t = 0$. Then

$$W_1^* = W_0 + brW_0 + vsW_0, \tag{2.8.4}$$

and

$$W_n^* = W_0[1 + br + vs]^n. \tag{2.8.5}$$

Dividing both sides of Eq. (2.8.5) by N and multiplying by r, we obtain

$$Y_{n+1}^* = Y_1[1 + br + vs]^n. \tag{2.8.6}$$

The earnings on a share at $t = 0$ are expected to grow at the rate br due to retention and at vs due to the sale of additional stock. Making the indicated substitutions, our stock value model becomes

$$P = \sum_{t=1}^{\infty} \frac{(1 - b)Y[1 + br + vs]^{t-1}}{(1 + k)^t}. \tag{2.8.7}$$

If $k > br + vs$, Eq. (2.8.7) becomes

$$P = \frac{(1 - b)Y}{k - br - vs}. \tag{2.8.8}$$

The only change in Eq. (2.7.8) necessary to recognize the expectation of continuous stock financing at the rate s is the change in the expected rate of growth to $br + vs$.

The meaning of v may be explained simply as follows. When a new issue is sold at a price per share $P = E$, the equity of the new shareholders in the firm is equal to the funds they contribute.

and the equity of the existing shareholders is not changed. However, if $P > E$, part of the funds raised accrues to the existing shareholders. Specifically, it can be shown that

$$= 1 - \frac{E}{P} \qquad (2.8.9)$$

is the fraction of the funds raised by the sale of stock that increases the book value of the existing shareholders' common equity. Also, v is the fraction of earnings and dividends generated by the new funds that accrues to the existing shareholders.

A more rigorous derivation of v follows. If the market for a firm's new shares is perfectly competitive, the number of shares given to new shareholders during $t = n$ in return for Q_n dollars must satisfy two conditions. The first is that the new issue must be sold at the prevailing price per share at the time of the issue. The other condition is that the dividend expectation a new shareholder obtains should have a present value equal to Q_n, the money he invests, when discounted at the rate k. With r the return the utility earns on common equity investment, b the retention rate, and $(1 - v)$ Q_n the book value of the common equity obtained by the new shareholders, their dividend in $n + 1$ will be

$$D^*_{n+1} = (1 - b)r(1 - v)Q_n. \qquad (2.8.10)$$

Once in the corporation the new shares are identical with the old shares. Their dividends also are expected to grow at the rate $br + vs$. Hence, the above two conditions are satisfied if

$$Q_n = \sum_{t=n+1}^{\infty} \frac{(1 - b)r(1 - v)Q_n(1 + br + vs)^{t-n-1}}{(1 + k)^{t-n}}$$

$$= \frac{(1 - b)r(1 - v)Q_n}{k - br - vs}. \qquad (2.8.11)$$

Dividing both sides of Eq. (2.8.11) by Q_n and solving for v, we obtain

$$v = \frac{r - k}{r - rb - s}. \qquad (2.8.12)$$

It can be shown that Eqs. (2.8.12) and (2.8.9) produce identical values of v. The interesting property of Eq. (2.8.12) is that it makes clear that the cost of new equity capital is ρ for continuous new equity financing as well as one-shot new equity financing. When $r = k$, $v = 0$, and new stock financing at the rate s has no impact on P. Of course, if $r = k$ then $x = \rho$. When $r > k$, v is positive, and share price increases with s.

The assumption that a utility is expected to stock finance at the rate s has implications for the measurement of k. The yield at which a share with continuous growth at the rate g sells is

$$k = \frac{D}{P} + g, \qquad (2.8.13)$$

the current dividend yield plus the expected rate of growth in the dividend. However, now $g = br + vs$ and not simply br. It also should be noted that continuous stock financing at the rate s poses problems similar to continuous retention at the rate b. When $k < br + vs$, the model breaks down in explosive growth. The above discussion of the resolution of the dilemma posed by $\rho < bx$ applies here. It also may have been noted from Eq. (2.8.12) that v is negative with $r > k$ when $r < rb + s$ or $r(1 - b) < s$. This is reasonable, although it may appear strange. Notice that $r(1 - b)$ and s are the outflow and inflow of funds due to dividends and stock financing expressed as fractions of the common equity. When $r(1 - b) < s$ the company is expected, in effect, to draw funds from stockholders for all future time. Clearly it is nonoptimal for a company to set $s > r(1 - b)$, and the case may be ignored.

2.9 *Finite Horizon Model*

We have seen that if $x > \rho$ and b and/or s are large we can have $k \leqslant g$, and our continuous growth models break down. A resolution of this dilemma consistent with the perfectly competitive capital markets assumptions is provided by withdrawing the assumption that the dividend is expected to grow at the current rate g for all future time. Specifically, a utility with a very large x reasonably will invest at a very high rate. The resultant high values

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Market Results for
Stocks, Bonds, Bills, and Inflation
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Chapter 2

Introduction to the Cost of Capital

Defining the Cost of Capital

Ibbotson® Stocks, Bonds, Bills, and Inflation® (SBBI®) historical data can be used, along with other inputs, to make forecasts of the future, including estimates of the cost of capital. A cost of capital estimate seeks to discern the expected return, or forecast mean return, on an investment in a security, firm, project, or division.

The cost of capital (sometimes called the expected or required rate of return or the discount rate) can be viewed from three different perspectives. On the asset side of a firm's balance sheet, it is the rate that should be used to discount to a present value the future expected cash flows. On the liability side, it is the economic cost to the firm of attracting and retaining capital in a competitive environment, in which investors (capital providers) carefully analyze and compare all return-generating opportunities. On the investor's side, it is the return one expects and requires from an investment in a firm's debt or equity. While each of these perspectives might view the cost of capital differently, they are all dealing with the same number.

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, the expectations of future events are the only factors that actually determine the cost of capital. An investor contributes capital to a firm with the expectation that the business's future performance will provide a fair return on the investment. If past performance were the criterion most important to investors, no one would invest in start-up ventures. It should also be noted that the cost of capital is a function of the investment, not the investor.

The cost of capital is an opportunity cost. Some people consider the phrase "opportunity cost of capital" to be

The Ibbotson® SBBI® Data Series

SBBI Data Series	Series Construction	Index Components	Approximate Maturity
1. Large Company Stocks	S&P 500 Composite with dividends reinvested. (S&P 500, 1957–Present; S&P 90, 1926–1956)	Total Return Income Return Capital Appreciation Return	N/A
2. Ibbotson Small Company Stocks	Fifth capitalization quintile of stocks on the NYSE for 1926–1981. Performance of the DFA U.S. 9-10 Small Company Portfolio January 1982–March 2001. Performance of the DFA U.S. Micro Cap Portfolio April 2001–Present.	Total Return	N/A
3. Long-Term Corporate Bonds	Citigroup Long-Term High Grade Corporate Bond Index	Total Return	20 Years
4. Long-Term Government Bonds	A One-Bond Portfolio	Total Return Income Return Capital Appreciation Return Yield	20 Years
5. Intermediate-Term Government Bonds	A One-Bond Portfolio	Total Return Income Return Capital Appreciation Return Yield	5 Years
6. U.S. Treasury Bills	A One-Bill Portfolio	Total Return	30 Days
7. Consumer Price Index	CPI—All Urban Consumers, not seasonally adjusted	Inflation Rate	N/A

The series presented here are total returns and, where applicable or available, capital appreciation returns and income returns. A description of the Center for Research in Security Prices small stock data is found in Chapter 7, Firm Size and Return.

REGULATORY FINANCE:

UTILITIES' COST OF CAPITAL

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in collaboration with
Lisa Todd Hillman

1994
PUBLIC UTILITIES REPORTS, INC.
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The *Hope* and *Bluefield* cases established the fundamental premise that investors should receive a return commensurate with returns currently available on comparable risk investments, not that investors be guaranteed a return coinciding with their initial return expectations. Consequently, the determination of a fair and reasonable return on equity should rest preferably on investor expectations, and historical risk premiums should be based on expected returns rather than on realized returns, data permitting.

While forward-looking risk premiums based on expected returns are preferable, historical return studies over long periods still provide a useful guide for the future. This is because over long periods investor expectations and realizations converge. Otherwise, investors would never commit investment capital. Investors expectations are eventually revised to match historical realizations, as market prices adjust to bring anticipated and actual investment results into conformity. In the long-run, the difference between expected and realized risk premiums will decline because short-run periods during which investors earn a lower risk premium than they expect are offset by short-run periods during which investors earn a higher risk premium than they expect.

Computational Issues

The third problem in relying on historical return results is the method of averaging historical returns.

Geometric v. Arithmetic Averages. One major issue relating to the use of realized returns is whether to use the ordinary average (arithmetic mean) or the geometric mean return. Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital. When using historical risk premiums as a surrogate for the expected market risk premium, the relevant measure of the historical risk premium is the arithmetic average of annual risk premiums over a long period of time. This is formally shown in *Principles of Corporate Finance*, a widely used and respected textbook on corporate finance by Brealey and Myers (1991). Appendix 11-A illustrates that only arithmetic averages can be used as estimates of cost of capital, and that the geometric mean is not an appropriate measure of cost of capital. A widely-used Ibbotson Associates publication title contains a rigorous discussion of the impropriety of using geometric averages in estimating the cost of capital (Ibbotson Associates 1993).

The use of the arithmetic mean appears counter-intuitive at first glance, because we commonly use the geometric mean return to measure the average annual achieved return over some time period. In estimating the cost of capital, the goal is to obtain the rate of return that investors expect,

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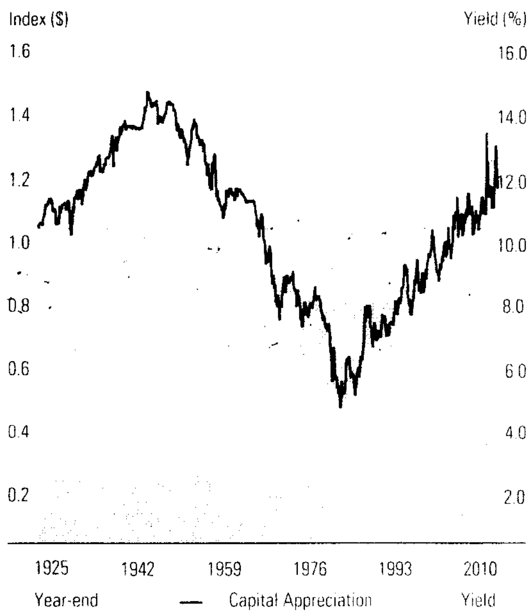
compared to an index of the long-term government bond capital appreciation. In general, as yields rose, the capital appreciation index fell, and vice versa. Had an investor held the long-term bond to maturity, he would have realized the yield on the bond as the total return. However, in a constant maturity portfolio, such as those used to measure bond returns in this publication, bonds are sold before maturity (at a capital loss if the market yield has risen since the time of purchase). This negative return is associated with the risk of unanticipated yield changes.

Graph 5-1: Long-term Government Bond Yields versus Capital Appreciation Index



Data from 1925–2010

For example, if bond yields rise unexpectedly, investors can receive a higher coupon payment from a newly issued bond than from the purchase of an outstanding bond with the former lower-coupon payment. The outstanding lower-coupon bond will thus fail to attract buyers, and its price will decrease, causing its yield to increase correspondingly, as its coupon payment remains the same. The newly priced outstanding bond will subsequently attract purchasers who will benefit from the shift in price and yield; however, those investors who already held the bond will suffer a capital loss due to the fall in price.

Anticipated changes in yields are assessed by the market and figured into the price of a bond. Future changes in yields that are not anticipated will cause the price of the bond to adjust accordingly. Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return.The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

Arithmetic versus Geometric Means

The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.

The argument for using the arithmetic average is quite straightforward. In looking at projected cash flows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods. Graph 5-2 shows the realized equity risk premium for each year based on the returns of the S&P 500 and the income return on long-term government bonds. (The actual, observed difference between the return on the stock market and the riskless rate is known as the realized equity risk premium.) There is considerable volatility in the year-by-year statistics. At times the realized equity risk premium is even negative.

QUANTITATIVE INVESTMENT ANALYSIS

Second Edition

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John Wiley & Sons, Inc.

Solution to 2: The distribution of PRFDX's annual returns appears to be mesokurtic, based on a sample excess kurtosis close to zero. With skewness and excess kurtosis both close to zero, PRFDX's annual returns appear to have been approximately normally distributed during the period.[48]

10. USING GEOMETRIC AND ARITHMETIC MEANS

With the concepts of descriptive statistics in hand, we will see why the geometric mean is appropriate for making investment statements about past performance. We will also explore why the arithmetic mean is appropriate for making investment statements in a forward-looking context.

For reporting historical returns, the geometric mean has considerable appeal because it is the rate of growth or return we would have had to earn each year to match the actual, cumulative investment performance. In our simplified Example 3-8, for instance, we purchased a stock for €100 and two years later it was worth €100, with an intervening year at €200. The geometric mean of 0 percent is clearly the compound rate of growth during the two years. Specifically, the ending amount is the beginning amount times $(1 + R_G)^2$. The geometric mean is an excellent measure of past performance.

Example 3-8 illustrated how the arithmetic mean can distort our assessment of historical performance. In that example, the total performance for the two-year period was unambiguously 0 percent. With a 100 percent return for the first year and −50 percent for the second, however, the arithmetic mean was 25 percent. As we noted previously, the arithmetic mean is always greater than or equal to the geometric mean. If we want to estimate the average return over a one-period horizon, we should use the arithmetic mean because the arithmetic mean is the average of one-period returns. If we want to estimate the average returns over more than one period, however, we should use the geometric mean of returns because the geometric mean captures how the total returns are linked over time.

As a corollary to using the geometric mean for performance reporting, the use of **semilogarithmic** rather than arithmetic scales is more appropriate when graphing past performance.[49] In the context of reporting performance, a semilogarithmic graph has an arithmetic scale on the horizontal axis for time and a logarithmic scale on the vertical axis for the value of the investment. The vertical axis values are spaced according to the differences between their logarithms. Suppose we want to represent £1, £10, £100, and £1,000 as values of an investment on the vertical axis. Note that each successive value represents a 10-fold increase over the previous value, and each will be equally spaced on the vertical axis because the difference in their logarithms is roughly 2.30; that is, $\ln 10 - \ln 1 = \ln 100 - \ln 10 = \ln 1{,}000 - \ln 100 = 2.30$. On a semilogarithmic scale, equal

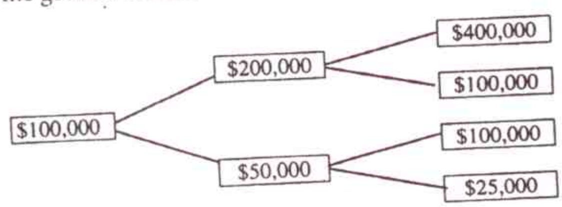
[48] It is useful to know that we can conduct a Jarque-Bera (JB) statistical test of normality based on sample size n, sample skewness, and sample excess kurtosis. We can conclude that a distribution is not normal with no more than a 5 percent chance of being wrong if the quantity $JB = n[(S_K^2/6) + (K_E^2/24)]$ is 6 or greater for a sample with at least 30 observations. In this mutual fund example, we have only 10 observations and the test described is only correct based on large samples (as a guideline, for $n \geq 30$). Gujarati (2003) provides more details on this test.

[49] See Campbell (1974) for more information.

movements on the vertical axis reflect equal percentage changes, and growth at a constant compound rate plots as a straight line. A plot curving upward reflects increasing growth rates over time. The slopes of a plot at different points may be compared in order to judge relative growth rates.

In addition to reporting historical performance, financial analysts need to calculate expected equity risk premiums in a forward-looking context. For this purpose, the arithmetic mean is appropriate.

We can illustrate the use of the arithmetic mean in a forward-looking context with an example based on an investment's future cash flows. In contrasting the geometric and arithmetic means for discounting future cash flows, the essential issue concerns uncertainty. Suppose an investor with $100,000 faces an equal chance of a 100 percent return or a −50 percent return, represented on the tree diagram as a 50/50 chance of a 100 percent return or a −50 percent return per period. With 100 percent return in one period and −50 percent return in the other, the geometric mean return is $\sqrt{2(0.5)} - 1 = 0$.



The geometric mean return of 0 percent gives the mode or median of ending wealth after two periods and thus accurately predicts the modal or median ending wealth of $100,000 in this example. Nevertheless, the arithmetic mean return better predicts the arithmetic mean ending wealth. With equal chances of 100 percent or −50 percent returns, consider the four equally likely outcomes of $400,000, $100,000, $100,000, and $25,000 as if they actually occurred. The arithmetic mean ending wealth would be $156,250 = ($400,000 + $100,000 + $100,000 + $25,000)/4. The actual returns would be 300 percent, 0 percent, 0 percent, and −75 percent for a two-period arithmetic mean return of (300 + 0 + 0 − 75)/4 = 56.25 percent. This arithmetic mean return predicts the arithmetic mean ending wealth of $100,000 × 1.5625 = $156,250. Noting that 56.25 percent for two periods is 25 percent per period, we then must discount the expected terminal wealth of $156,250 at the 25 percent arithmetic mean rate to reflect the uncertainty in the cash flows.

Uncertainty in cash flows or returns causes the arithmetic mean to be larger than the geometric mean. The more uncertain the returns, the more divergence exists between the arithmetic and geometric means. The geometric mean return approximately equals the arithmetic return minus half the variance of return.[50] Zero variance or zero uncertainty in returns would leave the geometric and arithmetic returns approximately equal, but real-world uncertainty presents an arithmetic mean return larger than the geometric. For example, Dimson et al. (2002) reported that from 1900 to 2000, U.S. equities had nominal annual returns with an arithmetic mean of 12 percent and standard deviation of 19.9 percent. They reported the geometric mean as 10.1 percent. We can see the geometric mean is approximately the arithmetic mean minus half of the variance of returns: $R_G \approx 0.12 - (1/2)(0.199^2) = 0.10$.

[50] See Bodie, Kane, and Marcus (2001).

By Michael Annin

Equity and the Small-Stock Effect

The capital asset pricing model shows risk inherent in return on equity. But something goes wrong when it's used for small-sized companies.

Does the size of a company affect the rate of return it should earn? If smaller companies should earn a higher return than larger firms, then small utilities, because of their size, should be allowed to adjust the rates they charge to customers.

By far the most notable and well-documented apparent anomaly in the stock market is the effect of company size on equity returns. The first study focusing on the impact that company size exerts on security returns was performed by Rolf W. Banz. Banz sorted New York Stock Exchange (NYSE) stocks into quintiles based on their market capitalization (price per share times number of shares outstanding), and calculated total returns for a value-weighted portfolio of the stocks in each quintile. His results indicate that returns for companies from the smallest quintile surpassed all other quintiles, as well as the Standard & Poor's 500 and other large stock indices. A number of other researchers have replicated Banz's work in other countries; nevertheless, a consensus has not yet been formed on why small stocks behave as they do.

One explanation for the higher returns is the lack of information on small companies. Investors must search more diligently for data. For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.

The Flaw in CAPM

One of the more common cost of equity models used in practice today is the capital asset pricing model (CAPM). The CAPM describes the expected return on any company's stock as proportional to the amount of systematic risk an investor assumes. The traditional CAPM formula can be stated as:

$$R_s = [\beta_s \times RP] + R_f$$

where:

R_s = expected return or cost of equity on the stock of company "s"

β = the *beta* of the stock of company "s"

RP = the expected equity risk premium

R_f = expected return on a riskless asset.

Table 1: The Size Premium in CAPM
(By Decile Portfolio in NYSE, 1926-94)

Decile	*Beta*	Arithmetic Mean Return	Actual Return in Excess of Riskless Rate**	CAPM Return in Excess of Riskless Rate**	Size Premium (Return in Excess CAPM)
1	0.90	11.01%	5.88%	6.33%	–0.44%
2	1.04	13.09	7.97	7.34	0.63
3	1.09	13.83	8.71	7.70	1.01
4	1.13	14.44	9.32	7.98	1.33
5	1.17	15.50	10.38	8.22	2.16
6	1.19	15.45	10.33	8.38	1.95
7	1.24	15.92	10.79	8.75	2.05
8	1.29	16.84	11.72	9.05	2.67
9	1.36	17.83	12.71	9.57	3.14
10	1.47	21.98	16.86	10.33	6.53

*Betas are estimated from monthly returns in excess of the 20-year government bond income return, January 1926-December 1994.
**Historical riskless rate measured by the 69-year arithmetic mean income return component of 20-year government bonds.
Source: SBBI 1995 Yearbook

Table 2: CAPM vs. CAPM w/ Size Premium

(By Percentile for Electric, Gas, and Sanitary Services Utilities)

	CAPM	CAPM with Size Premium
90th Percentile	16.42%	18.92%
75th Percentile	12.56%	14.72%
Median	10.89%	12.58%
25th Percentile	9.86%	11.39%
10th Percentile	8.63%	10.65%

(Weighted by Market Capitalization)

	CAPM	CAPM with Size Premium
Industry Composite	11.76%	12.33%
Large Company Composite	12.05%	12.07%
Small Company Composite	13.93%	17.95%

Source: Cost of Capital Quarterly '95 Yearbook by Ibbotson Associates
Note: Public utilities include electric, gas, and sanitary services companies.

Table 1 shows *beta* and risk premiums over the past 69 years for each decile of the NYSE. It shows that a hypothetical risk premium calculated under the CAPM fails to match the actual risk premium, shown by actual market returns. The shortfall in the CAPM return rises as company size decreases, suggesting a need to revise the CAPM.

The risk premium component in the actual returns (realized equity risk premium) is the return that compensates investors for taking on risk equal to the risk of the market as a whole (estimated by the 69-year arithmetic mean return on large company stocks, 12.2 percent, less the historical riskless rate). The risk premium in the CAPM returns is *beta* multiplied by the realized equity risk premium.

The smaller deciles show returns not fully explainable by the CAPM. The difference in risk premiums (realized versus CAPM) grows larger as one moves from the largest companies in decile 1 to the smallest in decile 10. The difference is especially pronounced for deciles 9 and 10, which contain the smallest companies.

Based on this analysis, we modify the CAPM formula to include a small-stock premium. The modified CAPM formula can be stated as follows:

$$R_s = [\beta_s \times RP] + R_f + SP$$

where:

SP = small-stock premium.

Because the small-stock premium can be identified by company size, the appropriate premium to add for any particular company will depend on its equity capitalization. For instance, a utility with a market capitalization of $1 billion would require a small capitalization adjustment of approximately 1.3 percent over the traditional CAPM; at $400 million, approximately 2.1 percent, and at only $100 million, approximately 4 percent.

Again, these additions to the traditional CAPM represent an adjustment over and above any increase already provided to these smaller companies by having higher *betas*.

Implications for Smaller Utilities

These findings carry important ramifications for relatively small public utilities. Boosting the traditional CAPM return by a full 400 basis points for small utilities translates into a substantial premium over larger utilities.

Table 2 shows the results of an analysis of 202 utility companies that calculated cost of equity figures. Composites (arithmetic means) weighted by equity capitalization were also calculated for the largest and smallest 20 companies. The results show the impact size has on cost of equity.

For the traditional CAPM, the large-company composite shows a cost of equity of 12.05 percent; the small company composite, 13.93 percent. However, once the respective small capitalization premium is added in, the spread increases dramatically, to 12.07 and 17.95 percent, respectively. Clearly, the smaller the utility (in terms of equity capitalization), the larger the impact that size exerts on the expected return of that security. ▼

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REGULATORY FINANCE:

UTILITIES' COST OF CAPITAL

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1994
PUBLIC UTILITIES REPORTS, INC.
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for such offerings in the first place, an unlikely event in public capital markets for small unproven companies. Internal sources of equity, including dividend reinvestment and/or employee stock option plans, are also typically less expensive, unless a discount on the purchase price is inherent in the plan, in which case they are often equivalent to a public issue. Direct costs are also incurred in an employee stock savings plan and/or a shareholder dividend reinvestment plan.

The flotation cost allowance is still warranted, however, because it is a composite factor that reflects the historical mix of all these sources of equity. The flotation cost allowance factor is a build-up of historical flotation cost adjustments associated and traceable to each component of equity source, and more specifically, is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the company. It is impractical and prohibitive to start from the inception of a company and source all present equity. A practical solution is to rely on the results of the empirical studies discussed earlier that quantify the average flotation cost factor of a large sample of utility stock offerings.

Richter (1982) demonstrated that the flotation cost allowance applicable to all the company's book equity is a weighted average of the current allowances required for each past financing, and suggested some practical means of circumventing the problem of vintaging each equity source. Richter essentially suggested sourcing book equity by broad categories of equity, such as dividend reinvestment plan equity, stock option equity, and public issue equity, and calculating a weighted average underpricing factor.

A third controversy centers around the argument that the omission of flotation cost is justified on the grounds that, in an efficient market, the stock price already reflects any accretion or dilution resulting from new issuances of securities and that a flotation cost adjustment results in a double counting effect. The simple fact of the matter is that whatever stock price is set by the market, the company issuing stock will always net an amount less than the stock price due to the presence of intermediation and flotation costs. As a result, the company must earn slightly more on its reduced rate base in order to produce a return equal to that required by shareholders.

It has also been argued that a flotation cost allowance is inequitable since it results in a windfall gain to shareholders. This argument is erroneous. As stated previously, the company's common equity account is credited by an amount less than the market value of the issue, so that the company must earn slightly more on its reduced rate base in order to produce a return equal to that required by shareholders.

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Business Valuation

One required element of the income approach to company valuation is the discount rate. Under the income approach, cash flows are projected into the future and discounted back to present value using a discount rate reflective of the risk inherent in those cash flows. The income approach is expressed in the following formula:

$$PV_s = \frac{CF_1}{(1+k_s)^1} + \frac{CF_2}{(1+k_s)^2} + \ldots + \frac{CF_i}{(1+k_s)^i}$$

where:

PV_s = the present value of the expected cash flows for company **s**;
CF_i = the dividend or cash flow expected to be received at the end of period **i**, and
k_s = the cost of capital for company **s**.

The discount rate is synonymous with the cost of capital.

While determining the appropriate future cash flow stream is an essential element of the income approach, determining the appropriate discount rate is equally important. Under the income approach, small changes in the discount rate can have a large impact on the ultimate value that is derived.

Table 2-2 is a simple valuation example that illustrates the impact of small changes in the discount rate. In the example, the entity being valued produces cash flows of $1,000 each year in years one through four, and $10,000 in year five. The lower portion of the table shows the values derived from this cash flow stream using different discount rates.

Table 2-2: Valuing Future Cash Flows with Different Discount Rates

Projected Cash Flows ($)

	Year 1	Year 2	Year 3	Year 4	Year 5
	1,000	1,000	1,000	1,000	10,000

Present Value of Cash Flows ($)

Discount Rate (%)	Year 1	Year 2	Year 3	Year 4	Year 5	Total
10	909	826	751	683	6,209	**9,379**
11	901	812	731	659	5,935	9,037
12	893	797	712	636	5,674	8,712
13	885	783	693	613	5,428	8,402
14	877	769	675	592	5,194	8,107
15	870	756	658	572	4,972	**7,827**

Whether this entity is worth $9,379 using a discount rate of 10 percent or $7,827 using a discount rate of 15 percent may seem trivial. If these values were in thousands or millions of dollars, however, the differences would be significant.

The preceding example focused on values produced from discount rates that are 500 basis points apart. While this may seem extreme, basic assumptions in the determination of the cost of capital can lead to discount rates that are widely divergent. Understanding the assumptions that underlie the discount rate is as important as understanding the assumptions that underlie the cash flows.

Regulatory Proceedings

Even in this era of deregulation, most utilities are regulated to some extent by local government bodies. An appointed commission ensures that the utility, because of its alleged monopolistic power, does not take advantage of its customers and that its investors receive a fair rate of return on their invested capital. One of the most important functions of the commission is to determine an appropriate (often called the "allowed") rate of return. The procedures for setting rates of return for regulated utilities often specify or suggest that the required rate is that which would allow the firm to attract and retain debt and equity capital over the long term.

Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital). In addition, certain regulatory environments may require that shareholders not earn more than the allowed rate of return. If a shareholder does earn more, future rates for the utilities services may be reduced by the regulating body. If the allowed rate of return falls below the cost of capital, regulators may allow a rate increase in order to compensate the investor so that they will on average over time earn the market-required rate of return. Yet other regulatory conditions may require that the allowed rate of return be different from the cost of capital.

FORWARD TEST YEARS

FOR US ELECTRIC UTILITIES

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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

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[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

<u>The Key Role of Unit Cost</u>

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

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[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:

$$\textit{growth Unit Cost} = \textit{growth Input Prices} - (\textit{growth Productivity} + \textit{Average Use}). \qquad [2]$$

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

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[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

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[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]

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[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.

<u>Colorado</u>

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,

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[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

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[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)

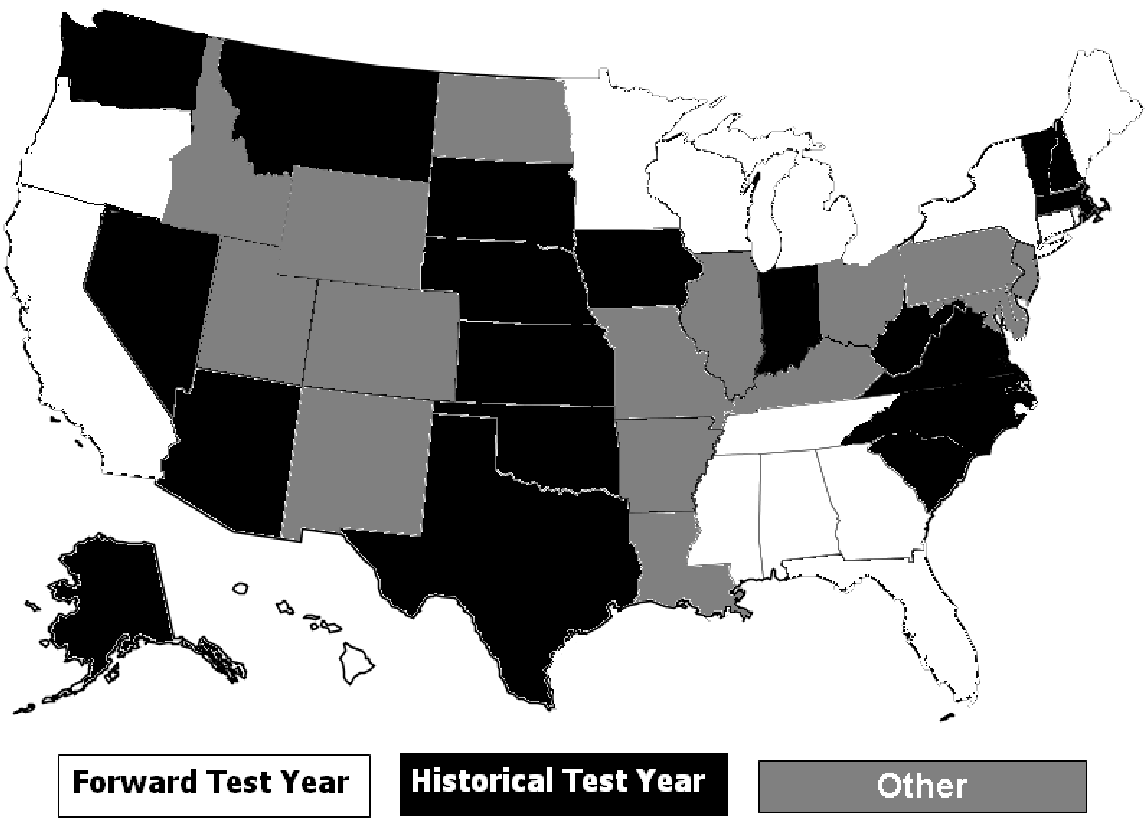
Utility Name	Notes
Colorado	Public Service of Colorado can file FTY evidence. No FTY rates have yet been approved but the most recent case made extraordinary HTY adjustments.
District of Columbia	PEPCO has filed rate cases using both hybrid and historical test years recently.
Delaware	Before restructuring 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

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[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

[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

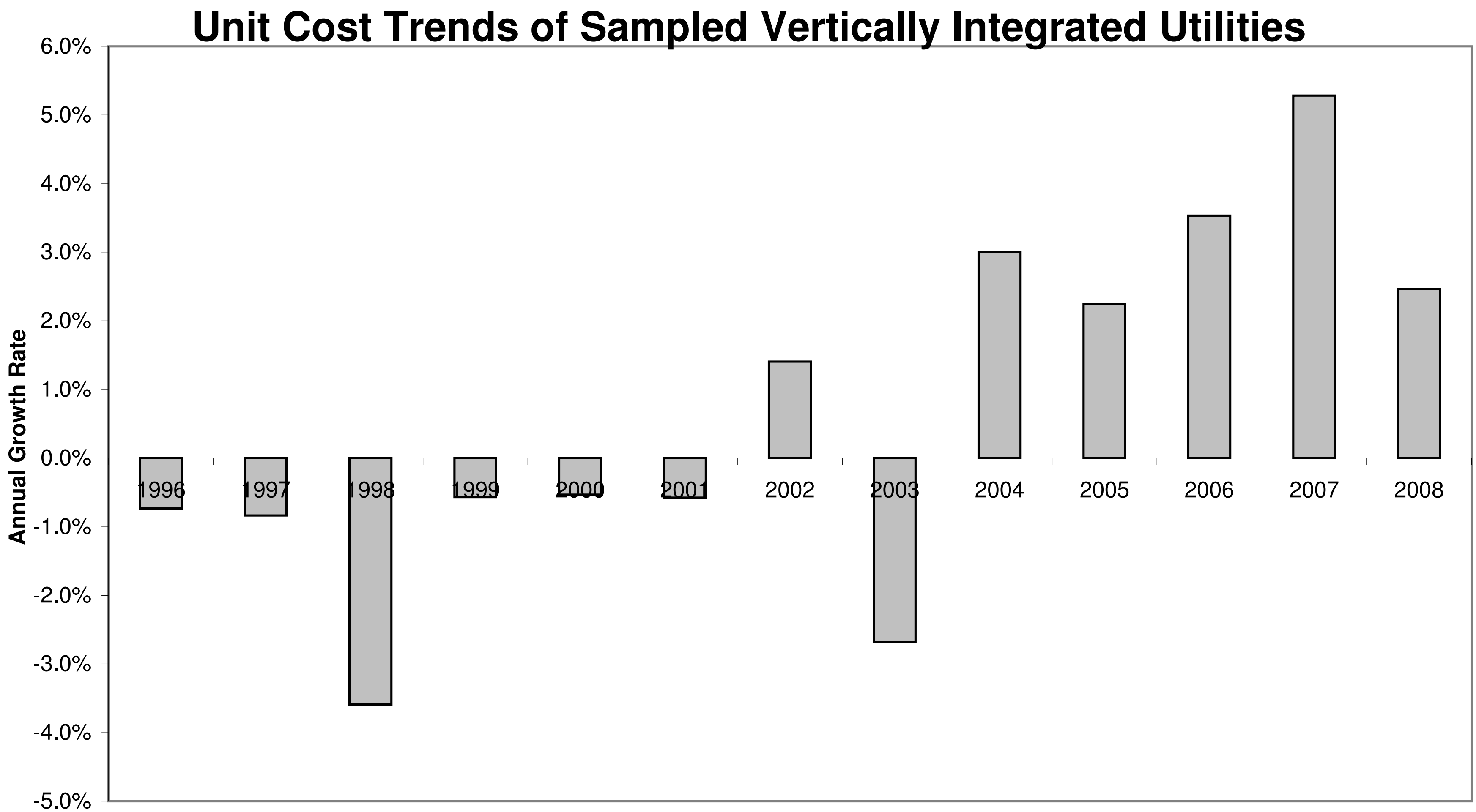
Sample Average Annual Growth Rates, Unweighted

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

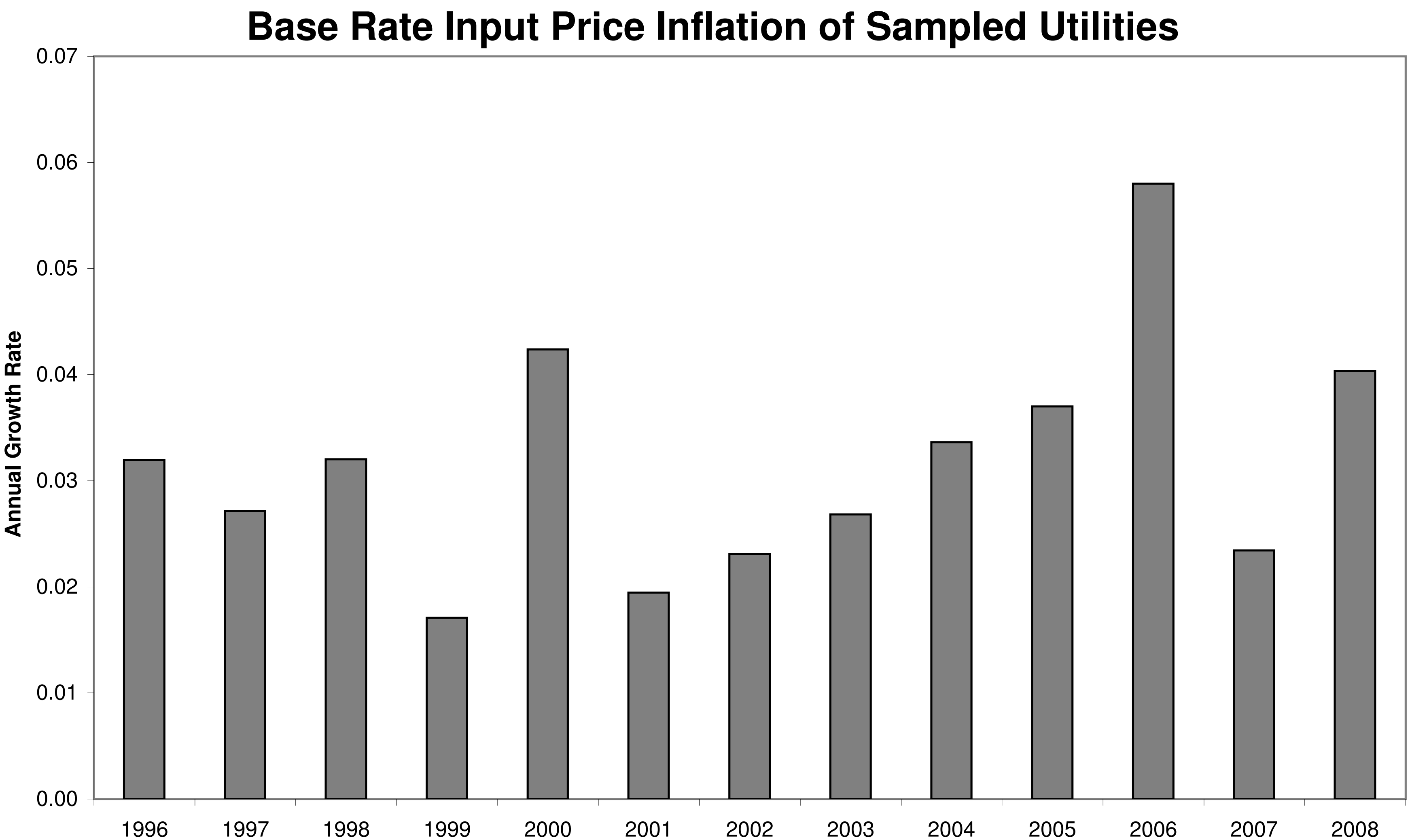
	Summary Input Price Index		Labor		Materials & Services		Capital	
Year	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate
1995	1.000		1.000		1.000		1.000	
1996	1.032	3.2%	1.033	3.2%	1.020	2.0%	1.034	3.3%
1997	1.061	2.7%	1.065	3.1%	1.042	2.1%	1.061	2.7%
1998	1.095	3.2%	1.108	4.0%	1.058	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

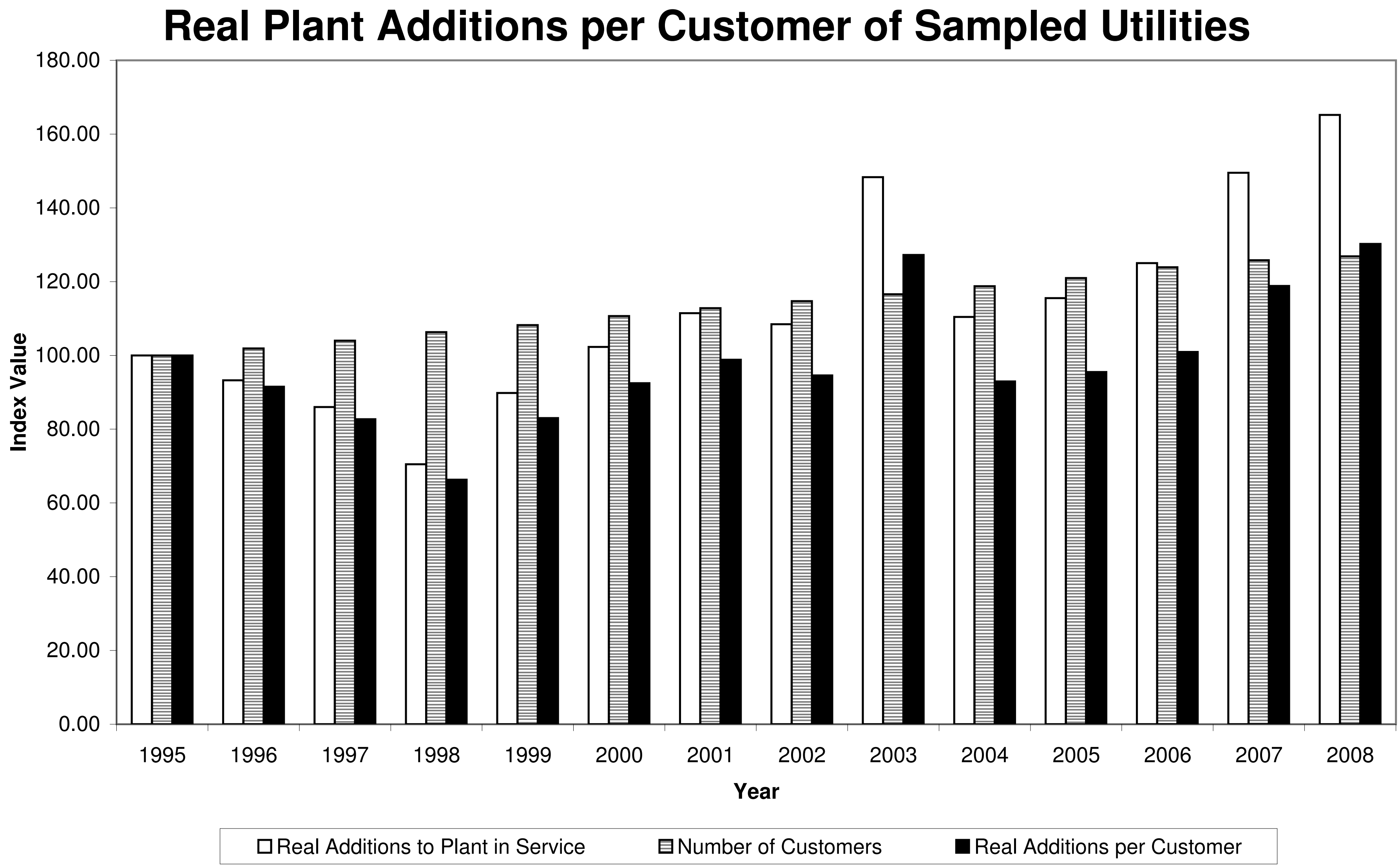

Real Plant Additions per Customer of Sampled Utilities
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Index Value
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
Year
Real Additions to Plant in Service
Number of Customers
Real Additions per Customer

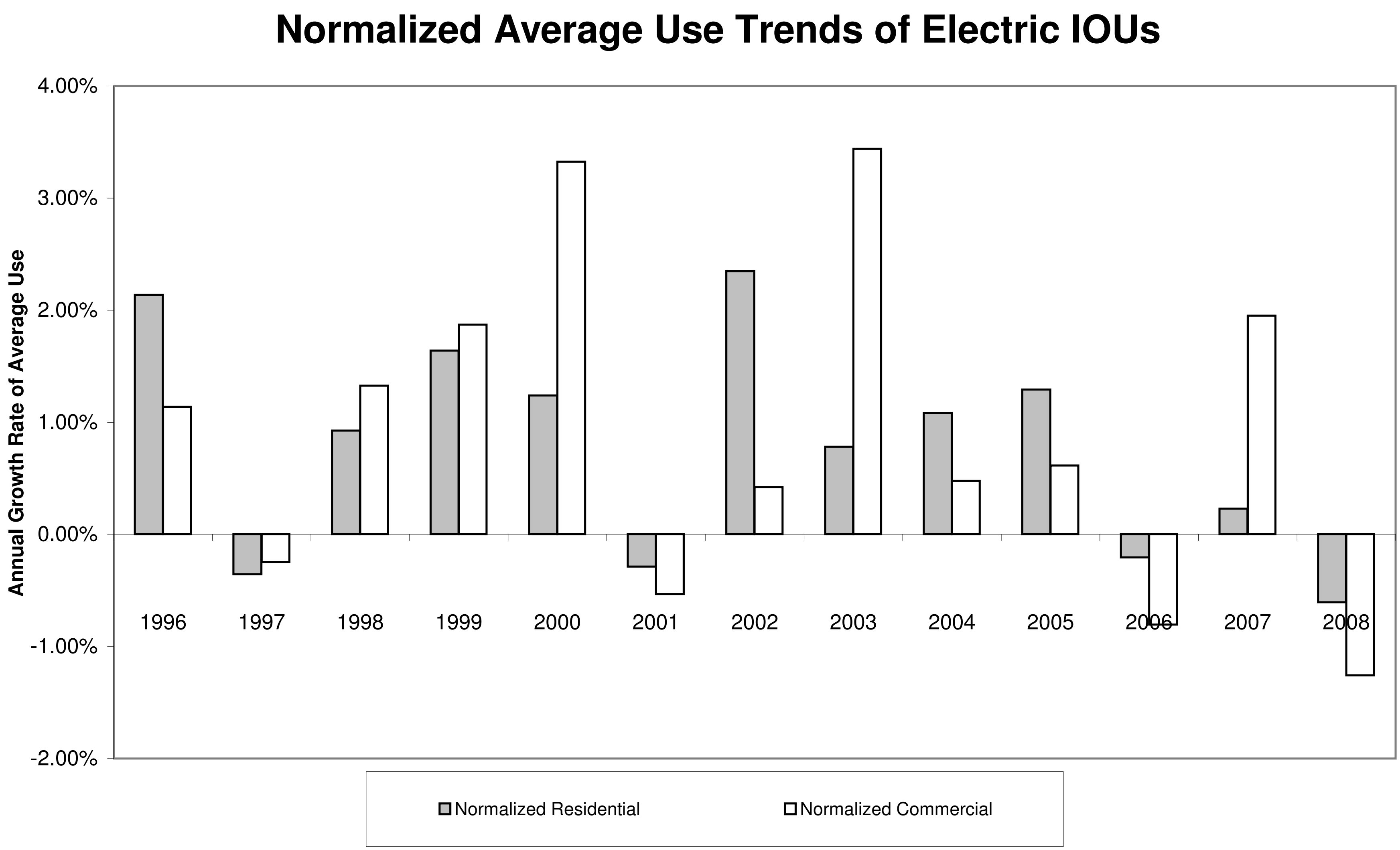
Table 7

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
Annual Growth Rate of Average Use
4.00%
3.00%
2.00%
1.00%
0.00%
-1.00%
-2.00%
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.

- 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 ($P_{t\text{-}2}$) and a volume ($V_{t\text{-}2}$) and this is set equal to the allowed cost of service

$$P_{t-2} \times V_{t-2} = Cost_{t-2}$$

so that

$$P_{t-2} = Cost_{t-2} / V_{t-2} = \text{Unit } Cost_{t-2}.$$

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

$$\begin{aligned} Cost_t \,/Revenue_t &= Cost_t / (P_{t-2} \times V_t) \\ &= Cost_t / [(Cost_{t-2} / V_{t-2}) \times V_t] \\ &= (Cost_t / V_t) / (Cost_{t-2} / V_{t-2}) \\ &= \text{Unit } Cost_t / \text{Unit } Cost_{t-2}. \qquad [A1] \end{aligned}$$

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

$$\text{Unit } Cost_t / \text{Unit } Cost_{t-2} = (Cost_t / Cost_{t-2}) / (V_t/V_{t-2}). \qquad [A2]$$

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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6-MONTH AVERAGE BOND YIELDS

	(a) Public Utility Bonds			
	BBB	**A**	**AA**	**AVG.**
Sep. 2014	4.79%	4.24%	4.18%	4.40%
Oct. 2014	4.67%	4.06%	3.98%	4.24%
Nov. 2014	4.75%	4.09%	4.03%	4.29%
Dec. 2014	4.70%	3.95%	3.90%	4.18%
Jan. 2015	4.39%	3.58%	3.52%	3.83%
Feb. 2015	4.44%	3.67%	3.62%	3.91%
Average	**4.62%**	**3.93%**	**3.87%**	**4.14%**

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	))))	**CASE NO. 2014-00371**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	))))	**CASE NO. 2014-00372**

REBUTTAL TESTIMONY

OF

JOHN J. SPANOS

Filed: April 14, 2015

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted testimony on November 26, 2014.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut the direct testimony of Kentucky Industrial Utility Customers, Inc. ("KIUC") witness, Lane Kollen, and the direct testimony of Kentucky Office of Attorney General witness, Frank W. Radigan on the subject of depreciation.

Q. WHAT ARE THE SPECIFIC DEPRECIATION SUBJECTS YOU WILL ADDRESS?

A. I will address witness Radigan's proposal to utilize a 50-year life span for the Cane Run Unit 7 combined cycle facility. Additionally, I will address witness Kollen's proposal to reduce the overall net salvage percent for all assets at the Cane Run Unit 7 generating facility.

Appropriate Life Span for Cane Run Unit 7

Q. DOES MR. RADIGAN PROPOSE A DIFFERENT LIFE SPAN FOR THE SOON-TO-BE COMPLETED CANE RUN UNIT 7?

A. Yes. Mr. Radigan has proposed a 50-year life span which is 10 years longer than my estimate.

Q. CAN YOU EXPLAIN MR. RADIGAN'S POSITION REGARDING THE LIFE SPAN OF COMBINED CYCLE FACILITIES?

A. Yes. Mr. Radigan states in his testimony, page 28, lines 16 and 17, that typical life spans for power plants are in the 50-60 year time frame. Additionally, he states he knows a few units that began operation in the 1970s. Both of these statements in regards to the life span of the Cane Run Unit 7 are not true indicators to utilize as a basis for a newly constructed combined cycle facility.

Mr. Radigan's statement regarding typical life spans of 50-60 years are generating facilities in the steam accounts such as major coal fired units and some large natural gas facilities. These are not related to combined cycle facilities, similar to Cane Run Unit 7.

Second, Mr. Radigan is referring to 1970s combined cycle units which also are not at all comparable to the type of facilities constructed today.

Q. ARE THE FEW COMBINED CYCLE FACILITIES BUILT IN THE 1970s COMPARABLE TO THE TYPE FACILITY CONSTRUCTED IN RECENT YEARS?

A. No. The combined cycle units built over 30 years ago were designed as peakers with low MW ratings. The units built today are demand driven units that operate by starts per year.

Q. WERE YOU AWARE OF THESE OLD COMBINED CYCLE FACILITIES?

A. Yes. Some of them I have actually seen during the conduct of a depreciation study. However, I do not consider the units comparable facilities which is why I did not include them in my industry range of 24-43 years. The units built since the 1990s have similar design, similar functionality and similar utilization.

Q. IS THE FACT THAT A FEW EARLY GENERATION COMBINED CYCLE UNITS HAVE STAYED IN SERVICE FOR 45 YEARS A REASON TO ESTIMATE A 50-YEAR LIFE SPAN FOR CANE RUN UNIT 7?

A. No. The units are not the same. For example, early generation steam facilities had a life span of 30-40 years. However, now we know 50-65 is more reasonable for the large steam units.

Q. ARE YOU FAMILIAR WITH THE TANGIBL SURVEY MR. RADIGAN UTILIZES AS HIS BASIS FOR INDUSTRY INFORMATION?

A. Yes. Many of the estimates in the statistics were from studies conducted by me or my firm. This is significant because I am aware of how each estimate, both interim survivor curve and life span, were determined. For example Mr. Radigan recommends a 100-year average life as an interim survivor curve. This is not appropriate for a combined cycle unit; that is what is utilized for the Structures account for large coal fired units. Combined cycle units are predominantly classified in the Other Production Plant accounts, 341-346, not the Steam accounts 311-316.

Q. CAN YOU SUMMARIZE THE POSITIONS OF YOU AND MR. RADIGAN IN THIS PROCEEDING?

A. Yes. I have estimated a 40-year life span that is consistent with many other combined cycle units which have been built in the last 20 years. These units are most comparable to Cane Run Unit 7. Additionally, the interim survivor curves utilized in my study are comparable to assets in Other Production Plant accounts which is where combined cycle units are generally classified.

Mr. Radigan proposes a 50-year life span because he is aware of a few combined cycle units built in the 1970s and the typical life span for unrelated steam units is 50-60 years. Also, he compares interim survivor curves for steam plants to combined cycle units which is not appropriate because they have different life characteristics.

Appropriate Net Salvage Percentage

Q. DOES MR. KOLLEN PROPOSE A DIFFERENT NET SALVAGE PERCENTAGE FOR EACH ACCOUNT FOR CANE RUN UNIT 7 THAN IN YOUR STUDY?

A. Yes. Mr. Kollen has proposed net salvage percentages which reduce my net salvage percentages by eliminating a component of terminal net salvage from the net salvage percentages I have proposed.

Q. DO THE NET SALVAGE PERCENTAGES YOU RECOMMEND INCLUDE A TERMINAL NET SALVAGE PERCENTAGE?

A. No, they do not.

Q. WHAT IS MR. KOLLEN'S BASIS FOR FURTHER REDUCING THE NET SALVAGE COMPONENT FOR EACH CANE RUN UNIT 7 ASSET CLASS?

A. Mr. Kollen asserts that since my study does not include a terminal net salvage component, then the net salvage percentage must be reduced in order to apply the interim net salvage to the percentage of assets which will be retired on an interim basis.

Q. DO YOU AGREE WITH THIS METHODOLOGY FOR ESTABLISHING A WEIGHTED NET SALVAGE PERCENTAGE?

A. Yes. This is one of the commonly used methods by my firm in estimating a weighted net salvage *when there is an estimate or understanding of the plan to dismantle the plant when retired*. However, this method is *not* applied for new facilities when no known plan for dismantlement is determined for the facility before it is placed in service.

Q. DID MR. KOLLEN UTILIZE THIS WEIGHTED NET SALVAGE METHODOLOGY IN A RECENT PROCEEDING IN SOUTH DAKOTA?

A. No, he did not. In that case, he recommended a total net salvage component for other production plant of negative 5 percent for all asset classes. The basis of his testimony in that proceeding was to maintain the same net salvage percentage which included a terminal net salvage component of negative 5 percent for all assets in Other Production Plant.[1]

Q. BASED ON HIS TESTIMONY IN THIS CASE, IS THERE ANY REASON HE WOULD NOT HAVE RECOMMENDED THE SAME ESTIMATE FOR CANE RUN UNIT 7?

A. No. The only reason he changed the net salvage percentages was based on my statement that I did not include a terminal net salvage component in my estimate. Therefore, Mr. Kollen reduced my recommended net salvage percent by using the weighted methodology in the South Dakota proceeding. However, I utilized an alternative method which already accounted for the reduced net salvage percent. I discuss the alternative method below.

Q. MR. KOLLEN CLAIMS ON PAGE 44 OF HIS TESTIMONY THAT YOU HAVE MADE A CALCULATION ERROR. IS THIS CORRECT?

A. No. Mr. Kollen was unaware of the alternative methodology utilized in my calculation to appropriately establish net salvage percentages at this time for Cane Run 7.

Q. HAVE YOU UTILIZED AN ALTERNATIVE METHODOLOGY FOR DETERMINING A NET SALVAGE PERCENTAGE FOR CANE RUN UNIT 7?

A. Yes. Another commonly utilized methodology for new facilities which do not have a plan for dismantlement is to establish an initial net salvage component that emphasizes the interim retirements. This method is utilized to properly record the most appropriate rate throughout the life of the facility and to avoid swings in the rate over time. Therefore, the net salvage percentages recommended are discounted from the total percentage of interim net salvage in order to properly align recovery patterns based on the interim survivor curve.

[1] In the matter of application of Black Hills Power, Inc., South Dakota Public Utilities Commission, Docket No. EL14-026.

Q. CAN YOU FURTHER EXPLAIN HOW YOU DETERMINED THE NET SALVAGE PERCENTAGES FOR CANE RUN UNIT 7?

A. Yes. The net salvage percentages were based on judgment which incorporated estimates of other utilities for interim net salvage as well as the estimated interim survivor curves selected for Cane Run Unit 7. For Cane Run Unit 7, the interim net salvage for Account 341, Structures and Improvements, and Account 346, Miscellaneous Power Plant Equipment is approximately negative 5 percent. Based on the interim survivor curve and type of assets in these accounts, the initial net salvage percentage should be 0 percent. The interim net salvage percent for Account 345, Accessory Electric Equipment, is approximately negative 5 percent and the negative 5 percent was utilized for the initial net salvage percent. For Account 342, Fuel Holders, Producers and Accessories; and Account 343, Prime Movers, the interim net salvage percentage should approximate 15-20 percent. However, based on the type of assets and interim survivor curve, negative 5 percent is recommended for the initial net salvage percent. For Account 344, Generators, the interim net salvage percentage should also approximate 15-20 percent; however, due to the higher expectation of interim retirements the initial net salvage percentage should be negative 10 percent.

Q. IS THERE A MATERIAL DIFFERENCE BETWEEN THE METHODOLOGIES YOU RECOMMENDED IN THIS CASE VERSUS THE ALTERNATIVE METHODOLOGY FOR SOME OTHER FACILITIES?

A. No. The primary difference is the depreciation expense by account. The method I recommend for this case is more appropriate when the terminal net salvage percentage or dismantlement plans are undefined, which is the case for Cane Run Unit 7 since this is the first type unit in the generation fleet.

Q. CAN YOU SHOW THE DIFFERENCE IN DEPRECIATION EXPENSE IF YOU EMPLOYED THE OTHER METHODOLOGY WITH THE APPROVED NEGATIVE 2 PERCENT TERMINAL NET SALVAGE?

A. Yes. The attached Rebuttal Exhibit JJS-1 sets forth the depreciation expense by account for Cane Run Unit 7 for Kentucky Utilities (KU) and Louisville Gas and Electric (LG&E). The annual difference is $38,492 for KU and $11,921 for LG&E. However, the depreciation expense is not a consistent pattern for each account for the initial depreciation rates.

Q. CAN YOU SUMMARIZE THE DIFFERENCES IN NET SALVAGE PERCENTAGES?

A. Yes. My net salvage percentages established an initial net salvage percent by account that reflects the anticipated percentage of net salvage to accrue per account based on interim survivor curves and no terminal net salvage in the early years. Mr. Kollen utilizes my discounted or weighted interim net salvage percentages and further discounts the percentages to eliminate plant that will be removed on a terminal basis. In essence, Mr. Kollen applies the 0 percent terminal net salvage percentage to a higher portion of the plant in service, thus, overstating the value of his reduction in expense.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) **SS:**
COUNTY OF CUMBERLAND)

The undersigned, **John J. Spanos**, being duly sworn, deposes and says that he is Senior Vice President of 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 Commonwealth, this 3rd day of April 2015.

(SEAL)
Notary Public

My Commission Expires:
February 20, 2019

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

REBUTTAL EXHIBIT JJS-1

KENTUCKY UTILITIES COMPANY
CANE RUN 7

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES BY COMPONENT AS OF APRIL 30, 2015
(Rebuttal Weighted NS% Calcuation)

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	ELECTRIC PLANT									
	OTHER PRODUCTION									
341	STRUCTURES AND IMPROVEMENTS	60-S1.5	*	(5)	67,731,300.00	0	71,117,865	1,861,724	2.75	38.2
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	55-R3	*	(5)	31,607,940.00	0	33,188,337	863,830	2.73	38.4
343	PRIME MOVERS	55-R2.5	*	(5)	103,854,660.00	0	109,047,393	2,894,039	2.79	37.7
344	GENERATORS	50-R1.5	*	(5)	203,193,900.00	0	213,353,595	6,035,462	2.97	35.4
345	ACCESSORY ELECTRIC EQUIPMENT	50-S0.5	*	(5)	36,123,360.00	0	37,929,528	1,073,578	2.97	35.3
346	MISCELLANEOUS POWER PLANT EQUIPMENT	45-R2	*	(5)	9,030,840.00	0	9,482,382	267,788	2.97	35.4
	TOTAL OTHER PRODUCTION PLANT				**451,542,000.00**	**0**	**474,119,100**	**12,996,421**	**2.88**	

* Life Span Procedure was used. Curve Shown is Interim Survivor Curve.

LOUISVILLE GAS AND ELECTRIC COMPANY
CANE RUN 7

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES BY COMPONENT AS OF APRIL 30, 2015
(Rebuttal Weighted NS% Calculation)

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	ELECTRIC PLANT									
	OTHER PRODUCTION									
341	STRUCTURES AND IMPROVEMENTS	60-S1.5	*	(5)	19,103,700.00	0	20,058,885	525,514	2.75	38.2
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	55-R3	*	(5)	8,915,060.00	0	9,360,813	243,835	2.74	38.4
343	PRIME MOVERS	55-R2.5	*	(5)	29,292,340.00	0	30,756,957	816,918	2.79	37.6
344	GENERATORS	50-R1.5	*	(5)	57,311,100.00	0	60,176,655	1,703,756	2.97	35.3
345	ACCESSORY ELECTRIC EQUIPMENT	50-S0.5	*	(5)	10,188,640.00	0	10,698,072	303,233	2.98	35.3
346	MISCELLANEOUS POWER PLANT EQUIPMENT	45-R2	*	(5)	2,547,160.00	0	2,674,518	75,637	2.97	35.4
	TOTAL OTHER PRODUCTION PLANT				127,358,000.00	0	133,725,900	3,668,893	2.88	

* Life Span Procedure was used. Curve Shown is Interim Survivor Curve.

LGE/KU
CANE RUN 7

TABLE 1. CALCULATION OF TERMINAL AND INTERIM RETIREMENTS AS A PERCENT OF TOTAL RETIREMENTS

Location	Total Projected Retirements	Total Terminal Retirements		Total Interim Retirements	
		Amount	(%)	Amount	(%)
(1)	(2)	(3)	(4)=(3)/(2)	(6)	(7)=(6)/(2)
Cane Run 7	578,900,000.00	434,701,201.16	75.09	144,198,798.84	24.91
Total	**578,900,000.00**	**434,701,201.16**	**75.09**	**144,198,798.84**	**24.91**

LGE/KU
CANE RUN 7

TABLE 2. CALCULATION OF WEIGHTED NET SALVAGE PERCENT

	Terminal Retirements		Interim Retirements		Weighted
Account	Retirements (%)	Net Salvage (%)	Retirements (%)	Net Salvage (%)	Average Net Salvage %
(1)	(2)	(3)	(4)	(5)	(6)=(2)*(3)+(4)*(5)
Other Production					
Can Run 7	75.09	(2)	24.91	(15)	(5)

LGE/KU
CANE RUN 7

INTERIM NS% CALCULATION

	ACCOUNT	NET SALVAGE PERCENT	ORIGINAL COST	INTERIM NS% CALC.
	(1)	(3)	(4)	
	ELECTRIC PLANT			
	OTHER PRODUCTION			
1	STRUCTURES AND IMPROVEMENTS	(5)	86,835,000.00	(0.75)
2	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	(15)	40,523,000.00	(1.05)
3	PRIME MOVERS	(15)	133,147,000.00	(3.45)
4	GENERATORS	(20)	260,505,000.00	(9.00)
5	ACCESSORY ELECTRIC EQUIPMENT	(5)	46,312,000.00	(0.40)
6	MISCELLANEOUS POWER PLANT EQUIPMENT	(5)	11,578,000.00	(0.10)
	TOTAL OTHER PRODUCTION PLANT		578,900,000.00	(14.75)

* Life Span Procedure was used. Curve Shown is Interim Survivor Curve.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2014-00371**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES	**))))**	**CASE NO. 2014-00372**

REBUTTAL TESTIMONY OF
DAVID J. WATHEN
DIRECTOR, SOUTHEAST TALENT & REWARDS PRACTICE LEADER
TOWERS WATSON

Dated: April 14, 2015

Q. Please state your name and your business address.

A. My name is David J. Wathen. My business address is 3500 Lenox Road, Suite 900, Atlanta, GA 30326.

Q. By who are you employed?

A. I have been employed by Towers Watson since 1996 and my position is Director, Southeast Talent & Rewards Practice Leader. Towers Watson is a leading global professional services company, which has 14,000 associates throughout the world, who offer solutions in the areas of employee benefits, talent management, rewards, and risk and capital management.

Q. Please explain the business of Towers Watson in providing compensation services.

A. Towers Watson advises organizations throughout the globe on all aspects of their compensation programs with the goal of paying people appropriately and enabling organizations to attract, retain and motivate employees efficiently and cost-effectively. Typical areas of compensation consulting assistance include pay philosophy development, variable or at-risk compensation plan design, total compensation benchmarking, and compensation structure development.

Q. Why do companies such as Kentucky Utilities Company ("KU") and Louisville Gas & Electric Company ("LG&E") retain consulting firms such as Towers Watson for compensation services?

A. Companies retain the services of compensation consultants like Towers Watson because they need access to the expertise and resources that consulting firms have to offer regarding current and emerging market practices, program design and market competitiveness. Towers Watson has extensive experience serving clients in the energy services industry, having served more than 150 energy services industry organizations last year. Because we invest heavily in our energy services industry capabilities, we have rich competitive industry information that enables KU and LG&E to benchmark against similar companies in the U.S. Given Towers Watson's breadth and depth of resources, we are frequently engaged by companies to conduct competitive assessments of total rewards programs including compensation levels by position, at-risk compensation plan design, pay structures and other consulting services.

Q. What are your responsibilities as the Director, Southeast Talent & Rewards Practice Leader at Towers Watson?

A. I manage Towers Watson's compensation, talent management, change management and communications consulting practices in the Southeast, which includes over 40 professional and administrative staff. My key areas of responsibility include:

- Managing, supporting and executing compensation projects and business development initiatives to retain current clients and expand existing relationships, projects entail assisting management and/or Boards of Directors in managing all aspects of their compensation programs,

- Contributing to the development of plans and budgets, delivering planned performance and ensuring the various consulting practices achieve their defined goals,
- Integrating and building team resources into an effective client service delivery team, developing and executing strategic staffing plans and attracting and maintaining engagement and retention of key talent,
- Overseeing all aspects of local delivery of Towers Watson products and services for the Southeast Talent & Rewards practice and collaborating with other lines of business to develop local market strategies to broaden and build client relationships.

In addition to my leadership and consulting responsibilities, I have been a guest speaker on executive compensation to professional and academic organizations including the Atlanta Area Compensation Association, Emory University, National Association of Stock Plan Professionals, Society of Corporate Secretaries and Governance Professionals and Vanderbilt University.

Q. Please share your educational background.

A. I graduated from Vanderbilt University in 1990 with a B.A. in Economics and earned an M.B.A. with an emphasis in Human Resources from The Owen Graduate School of Management at Vanderbilt University in 1996.

Q. KU and LG&E have offered you as an expert witness on utility compensation programs. What qualifications do you have to testify as an expert on utility compensation programs?

A. In my 19 year career with Towers Watson, I have assisted management and Boards of Directors at numerous companies in designing and assessing all aspects of their compensation programs. Since joining the firm in 1996, I have consulted with numerous utilities and currently serve as the leader of the firm's utility industry compensation practice. I have conducted competitive assessments of total compensation levels and at-risk compensation plans for numerous utilities and currently provide compensation consulting services to several utility clients located across the U.S.

In addition, I have filed testimony in other regulatory proceedings in several jurisdictions, including: Florida, Illinois, Indiana, Mississippi and Wisconsin on the subject of utility compensation.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. Towers Watson was asked by KU and LG&E to analyze the projected 2015 and 2016 average salary budgets, competitive market positioning of target total cash compensation (base salary and target short-term at-risk compensation) and total employee headcounts compared to comparably-sized utilities in response to testimony from Witnesses Ronald Willhite, Frank Radigan and Lane Kollen.

Q. What are the conclusions of your analysis?

A. Overall, our analysis indicates that KU and LG&E projected 2015 and 2016 average salary budgets and target total cash compensation levels are competitive with market levels. KU and LG&E need to provide market competitive compensation in order to attract, retain and motivate the critical talent needed to successfully run their respective companies.

Our assessment of total employee headcounts relative to comparably-sized, regulated utilities indicates that KU, LG&E and LKE (the combined entity with all service employees included) total current and projected headcounts fall below the market 50th percentile headcounts of utility peers.

Salary Budgets

Towers Watson compared the projected 2015 and 2016 average base salary budgets of 3.0% at KU and LG&E to published market data from the 2014 WorldatWork Salary Budget Survey, a key source of salary budget data in the U.S. Projected 2015 50th percentile (median) total salary budgets for all employee groups in the utility industry are expected to be 3.0%, which aligns with the projected 2015 and 2016 average salary budgets for KU and LG&E (projected 2016 salary budget market data is not expected to be available until mid to late summer 2015).

Target Total Cash Compensation Competitive Market Positioning

Towers Watson assessed the competitiveness of compensation levels based on KU's and LG&E's stated compensation philosophy, which is to target compensation at the 50th percentile of the applicable market for talent. To conduct this analysis we reviewed data provided to us by KU and LG&E and examined published general and energy services industry compensation surveys available to Towers Watson, including our proprietary 2014 Energy Services and General Industry Compensation surveys, reflecting over 110 and 440 survey participants, respectively. Towers Watson has been conducting these surveys for over 20 years.

In conducting the competitive assessment of target total cash compensation, Towers Watson examined 345 positions, covering 2,145 employees or approximately 60% of the combined KU, LG&E and services company workforce. When determining the competitiveness of pay relative to the market, Towers Watson defines a position as being competitive or "at market" if it is within +/-10% variance of the market for non-executive positions. Variances within this range are often explained by different experience levels and tenure of the incumbents. Likewise, we believe it is important to examine compensation levels within a range given data often shift due to year-to-year changes in data samples and survey participation.

Overall, we have determined that KU's and LG&E's target total cash compensation (base salary + short-term at-risk compensation) is competitive with the 50th percentile of the market (i.e., within +/-10% variance of the market) as it falls within the market competitive range. See Exhibit 1 for details of this analysis by job level.

<u>Total Employee Headcount</u>

Towers Watson compared the March 2014 employee headcount of KU, LG&E and LKE (the combined entity with all service employees included) to disclosed headcount totals of other utilities. Given limited disclosure of headcount totals for subsidiary or operating companies like KU and LG&E, Towers Watson examined disclosed headcount totals for comparable, publicly-traded utilities (i.e., revenues in a range of approximately ½ to 2-times, vertically integrated, regulated utilities, etc.) to provide a market reference point for comparison. The data source for the utility peer headcount totals are the most recently published 10K filings, reflecting data for the 2014 fiscal year.

Based on the data examined, March 2014 and projected 2016 headcount totals for KU, LG&E and LKE fall below the market 50th percentile of utility peers. The table below presents summary findings (see Exhibit 2 for details):

Organization	Current Total Headcount (3/31/14)	Projected Total Headcount (6/30/16)	Utility Peers Market 50th %ile Total Headcount (12/31/2014)
LG&E	1,707	1,786	1,887
KU	1,787	1,868	2,021
LKE	3,509	3,668	4,230

Q. How does your analysis relate to Mr. Willhite's salary budget testimony?

A. Mr. Willhite recommends a 1.0% to 1.5% salary budget increase for the test year. As available market data shows, projected 2015 salary budgets for utilities are expected to be 3.0%, which is double of what Mr. Willhite recommends. In order to continue to provide market competitive base salaries that enable the company to attract and retain talent, both KU and LG&E will need to provide market competitive base salary budgets well above what Mr. Willhite recommends.

Q. How does your analysis relate to Mr. Kollen's incentive compensation testimony?

A. Mr. Kollen recommends disallowance of all short-term at-risk compensation tied to financial performance at KU and LG&E. The competitive target total cash compensation analysis we conducted indicates that KU and LG&E need to include the short-term at-risk compensation in order to provide a market competitive level of pay.

If part of the short-term at-risk compensation at KU and LG&E were eliminated, the companies could look to increase fixed pay (i.e., base salary) to above market competitive levels in order to attract and retain talent. This approach would be counter to the pay-for-performance philosophy, which is to put short-term incentives "at-risk", which allows KU and LG&E to differentiate pay based on performance and allocate compensation to those employees that are most deserving.

Given aging workforces in the utility sector, the need to replace critical skills will only grow as employees retire; therefore, it is critical that KU and LG&E are able to attract, retain and motivate skilled employees. As noted in Towers Watson's target total cash compensation assessment, current pay levels at KU and LG&E are aligned with competitive market levels and serve to achieve the goals of attraction, retention and motivation of employees, focused on delivering safe, reliable and cost effective services to customers.

Q. How does your analysis relate to Messrs. Kollen and Radigan's head count testimony?

A. I am not qualified to speak to what headcount is necessary or essential to KU, LG&E and LKE, but Towers Watson was able to provide publicly-disclosed headcount data for comparable, publicly-traded utilities to serve as a reference point for comparison to the current and projected headcounts at KU, LG&E and LKE. Based on a review of the data available, the current and projected headcounts for KU, LG&E and LKE fall below the market 50^{th} percentile headcount of utility peers (See Exhibit 2 for details).

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

STATE OF GEORGIA)
) **SS:**
COUNTY OF FULTON)

The undersigned, **David J. Wathen,** being duly sworn, deposes and says he is Director, Southeast Talent & Reward Practice Leader, at Towers Watson in Atlanta, Georgia, and that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

David J Wathen

DAVID J. WATHEN

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 7 day of April, 2015.

(SEAL)

Vickie Lynn Westbrook
Notary Public

My Commission Expires:

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VICKIE LYNN WESTBROOK
Notary Public, Georgia
Cobb County
My Commission Expires
March 14, 2018

David Wathen

David Wathen is the practice leader for Towers Watson's Talent & Rewards practice in Atlanta. He has more than nineteen years of experience assisting Boards of Directors and management in managing all aspects of their compensation programs. David specializes in the competitive assessment of total compensation levels, as well as the design and implementation of annual and long-term incentive plans. During his consulting career, David has worked with clients in numerous industries, including: consumer products, financial services, energy services, healthcare, high-tech, manufacturing and transportation.

David also serves as the leader of the firm's utility industry compensation practice, having conducted assignments with numerous utilities. David has provided rate case support to several utilities, including expert witness testimony in several states (see table below for details).

David has been a guest speaker on executive compensation to professional and academic organizations including: Emory University, NASPP, Society of Corporate Secretaries and Governance Professionals and Vanderbilt University and has been published in *Executive Talent Magazine*.

Before joining Towers Perrin in 1996, David was employed for four years as a Project Manager/Systems Support Specialist by Schlumberger Industries, where he trained and supported utilities in the use of computerized reading systems.

David received a bachelor's degree in economics from Vanderbilt University and an MBA from the Owen Graduate School of Management at Vanderbilt University with concentrations in human resources and general management. He is a member of WorldatWork.

Utility Expert Witness Testimony

Date	Case	Utility	State	Subject
11/2011	1101238-EI	Gulf Power Company	Florida	Compensation and at-risk incentive design competitiveness
5/2014	2013-UN-189	Mississippi Power Company	Mississippi	Compensation and at-risk incentive design competitiveness
7/2014	44462	Citizens Energy Group	Indiana	Executive compensation benchmarking methodology
7/2014	14-0312	Commonwealth Edison Company	Illinois	Short-term at-risk incentive design competitiveness
9/2014	6690-UR-123	Wisconsin Public Service Corporation	Wisconsin	Compensation competitiveness

Competitive Target Total Cash Compensation Assessment by Job Level

Job Level	# of Jobs	# of EEs	Variance to Market 50th %ile	
			Base Salary	Target Total Cash Comp.
Senior Management	32	32	5.7%	3.3%
Non-Exempt	16	413	2.7%	5.0%
Management	66	108	3.9%	4.0%
Hourly	6	144	0.4%	4.4%
Exempt	202	955	1.0%	2.8%
Bargaining Unit	23	493	2.2%	4.4%
Total	**345**	**2,145**	**1.8%**	**3.7%**

Total Headcount Analysis Summary and By Utility Details

Current Headcount versus Utility Peers

Organization	2014 Revenue Size (Millions $)	Current Headcount Data (3/31/14)		Utility Peer Market Data (as of 12/31/14)				
		Headcount (w/out Service Co. Ees)	Headcount (w/ Service Co. Ees)	# of Utilities in Sample	25th Percentile Total Headcount	50th Percentile Total Headcount	75th Percentile Total Headcount	Variance Versus Market 50th %ile
LG&E	$1,450	1,020	1,707	12	1,620	1,887	2,684	**-180**
KU	$1,720	955	1,787	13	1,625	2,021	2,935	**-234**
LKE	$3,170	--	3,509	12	3,231	4,230	4,713	**-721**

Projected Headcount versus Utility Peers

Organization	2014 Revenue Size (Millions $)	Projected Headcount Data (6/30/16)		Utility Peer Market Data (as of 12/31/14)				
		Headcount (w/out Service Co. Ees)	Headcount (w/ Service Co. Ees)	# of Utilities in Sample	25th Percentile Total Headcount	50th Percentile Total Headcount	75th Percentile Total Headcount	Variance Versus Market 50th %ile
LG&E	$1,450	1,068	1,786	12	1,620	1,887	2,684	**-101**
KU	$1,720	973	1,868	13	1,625	2,021	2,935	**-153**
LKE	$3,170	--	3,668	12	3,231	4,230	4,713	**-562**

Total Headcount Analysis Summary and By Utility Details (continued)

LG&E Utility Peer Group

Peer Companies	FYE Revenues (Millions $)*	Total Employees*
ALLETE	$1,137	1,625
Avista	$1,473	1,874
Black Hills	$1,394	2,021
Cleco	$1,269	1,206
El Paso Electric	$918	1,000
Great Plains Energy Incorporated	$2,568	2,935
NorthWestern Energy	$1,205	1,604
OGE Energy	$2,453	3,329
Otter Tail	$799	1,893
PNM Resources	$1,436	1,881
Portland General Electric	$1,900	2,600
TECO Energy	$2,566	4,400

n= 12

25th Percentile	**$1,188**	**1,620**
50th Percentile	**$1,415**	**1,887**
75th Percentile	**$2,038**	**2,684**

LG&E (Current)	**$1,450**	**1,707**
Percentile Rank	**58%**	**30%**

LG&E (PROJECTED)	**$1,450**	**1,786**
Percentile Rank	**58%**	**33%**

* Data source: Standard & Poor's Capital IQ Financial Database and utility 10K filing.

Total Headcount Analysis Summary and By Utility Details (continued)

KU Utility Peer Group

Peer Companies	FYE Revenues (Millions $)*	Total Employees*
ALLETE	$1,137	1,625
Avista	$1,473	1,874
Black Hills	$1,394	2,021
Cleco	$1,269	1,206
El Paso Electric	$918	1,000
Great Plains Energy Incorporated	$2,568	2,935
NorthWestern Energy	$1,205	1,604
OGE Energy	$2,453	3,329
PNM Resources	$1,436	1,881
Portland General Electric	$1,900	2,600
TECO Energy	$2,566	4,400
Vectren	$2,612	5,500
Westar Energy	$2,602	2,411

n= 13

25th Percentile	**$1,269**	**1,625**
50th Percentile	**$1,473**	**2,021**
75th Percentile	**$2,566**	**2,935**

KU (Current)	**$1,720**	**1,787**
Percentile Rank	**55%**	**30%**

KU (PROJECTED)	**$1,720**	**1,868**
Percentile Rank	**55%**	**33%**

* Data source: Standard & Poor's Capital IQ Financial Database and utility 10K filing.

Total Headcount Analysis Summary and By Utility Details (continued)

LKE Utility Peer Group

Peer Companies	FYE Revenues (Millions $)*	Total Employees*
Alliant Energy	$3,350	4,212
Ameren	$5,838	8,527
Great Plains Energy Incorporated	$2,568	2,935
Hawaiian Electric Industries Inc.	$3,240	3,965
Integrys Energy Group	$4,144	4,575
OGE Energy	$2,453	3,329
Pepco Holdings	$4,878	5,125
Portland General Electric	$1,900	2,600
TECO Energy	$2,566	4,400
Vectren	$2,612	5,500
Westar Energy	$2,602	2,411
Wisconsin Energy	$4,997	4,248

n= 12

25th Percentile	**$2,568**	**3,231**
50th Percentile	**$2,926**	**4,230**
75th Percentile	**$4,328**	**4,713**

LKE (Current)	**$3,170**	**3,509**
Percentile Rank	**54%**	**30%**

LKE (PROJECTED)	**$3,170**	**3,668**
Percentile Rank	**54%**	**32%**

* Data source: Standard & Poor's Capital IQ Financial Database and utility 10K filing.